CALIFORNIA
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ACCELERATED RENEWABLE ENERGY DEVELOPMENT

Prepared in support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEPR-01)

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ABSTRACT

The 2003 *Integrated Energy Policy Report* recommended that the state accelerate renewable energy development to help increase fuel diversity in California's electricity supply, taking into account the resource mix of each utility, transmission needs and infrastructure, and the availability of cost-effective renewable resources. This draft staff white paper discusses rules in place and progress toward reaching 20 percent by 2010 through the accelerated renewables portfolio standard, including the status of publicly owned electric utilities. The paper also discusses the need for accelerated renewables portfolio standard targets after 2010 and utility-specific targets beyond 20 percent. This paper reports the status of public dialogue regarding the possible use of unbundled renewable energy certificates. Finally, the paper discusses the challenges facing distributed photovoltaic generation incentive programs in California to keep up with demand and possible changes to program structure and incentives.

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EXECUTIVE SUMMARY

Building on expected trends in energy efficiency, renewable energy development, transmission planning, and aging fossil-fuel electricity generation, this white paper on accelerated renewable energy development furthers public dialogue and implementation of the recommendations of the *2003 Integrated Energy Policy Report* (*Energy Report*). This white paper also identifies risks and challenges affecting accelerated renewable energy development.

This white paper highlights trends and policy responses that can affect the rate of growth of new investment in California's renewable energy market. If new investment in renewable energy slows, the fuel supply for California's electricity is expected to become increasingly dependent on natural gas. Continued investment in renewable energy is important to increasing fuel diversity and associated benefits for California's electricity supply.

Increasing fuel diversity is one of three key issues highlighted in the 2003 *Energy Report* regarding California's electricity generation system. To reduce the demand for natural gas used to generate electricity, the report recommended expanding energy efficiency and renewable energy development efforts. Regarding renewable energy, the report recommended enacting state legislation to require that all retail suppliers of electricity meet the Renewables Portfolio Standard (RPS) goal of 20 percent of retail electricity sales and accelerate the target date for reaching the goal from 2017 to 2010. Another way to reduce demand for natural gas used to generate electricity, especially during peak periods, is through renewable distributed generation. The 2003 *Energy Report* recommended that the state should support distributed generation alternatives for consumers, with a preference for renewable resources.

2004 Update on Accelerated Renewable Energy Development

Progress has been made in the RPS program since publication of the 2003 *Energy Report.* Both Pacific Gas and Electric Company and San Diego Gas & Electric have released their first formal RPS procurement solicitations. Southern California Edison will not hold an RPS solicitation this year as the utility claims it will reach 20 percent renewables in 2004.

Recent decisions regarding details of the RPS program have been particularly important in clarifying the amount of additional energy required for the RPS, and the approach that will be used to solicit, compare, and rank competitive bids. Rules have also been set recently regarding allocation of supplemental energy payments. For further information on these and related decisions for the RPS, see CPUC proceedings R.04-04-026 and I.00-11-001, and California Energy Commission (Energy Commission) guidebooks for the RPS program.[1]

At the end of 2003, investor-owned utilities (IOUs) appeared to be ahead of schedule regarding the minimum amount that is required to meet the state's accelerated renewable energy goals. Since the end of 2001, the investor-owned utilities have increased their use of central-station renewables by approximately 4,000 GWh, or over two percentage points each, through interim solicitations. The energy procured to date has not been supported with supplemental energy payments, though several projects selling energy to the IOUs have received financial support from the Energy Commission's renewable program.[2]

Publicly owned electric utilities have also made progress implementing RPS programs, although their programs differ significantly from the RPS program for IOUs, electric service providers, and community choice aggregators. Each publicly owned electric utility is required to implement and enforce a RPS. The law does not delineate precise program details, but it does state that the RPS programs implemented by the publicly owned electric utilities should take into account the potential impacts of renewable energy on rates, reliability, financial resources, and the goal of environmental improvement.[3]

As of June 2004, most of the state's publicly owned electric utilities have adopted RPS plans to reach 20 percent renewable energy by 2017. Few publicly owned electric utilities have adopted an accelerated RPS program, with the notable exception of the Sacramento Municipal Utility District (i.e., 20 percent by 2011). In contrast to the RPS for IOUs, electric service providers, and community choice aggregators, RPS programs established by all but a few publicly owned electric utilities include large hydropower as a qualifying renewable energy source. Contrary to the spirit of the RPS, the *2003 Energy Report*, and the *Energy Action Plan*, this reduces the significance of the 20 percent target for development of new renewable energy to meet growing electricity retail sales in California.

2004 Accelerated Renewable Energy Development Draft Staff White Paper

After reporting progress made toward reaching 20 percent by 2010, this white paper discusses development of more ambitious RPS goals for the post-2010 period. The aim of such goals would be to avoid losing momentum, continue pushing technology innovation, and drive costs down for renewables. The staff believes that there is a need for longer-term goals to provide certainty and stability for the continued healthy growth of the industry and in responding to the desires of the California public.

In studying the resource mix of each utility, it becomes clear that individual utilities face different constraints and opportunities in developing renewable energy. If a utility reaches the accelerated RPS goal of 20 percent renewable energy before

2010, this white paper suggests that it should be encouraged to continue accelerated renewable energy development beyond the minimum level required to maintain this achievement.

Beyond the resource mix of each utility, the cost and availability of transmission access greatly affects the location and timing of cost-effective development to meet California's long-term renewable targets. The Energy Commission, California Independent System Operator, CPUC, and others are working on improving the transmission system planning process in California, including issues related to renewable energy. In contrast to traditional electricity sources, renewable energy is usually developed in small increments by a number of independent developers over varying time schedules, except for geothermal. This poses a dilemma for transmission planning, as it is usually not known for certain far enough in advance whether renewable energy will be developed in sufficient quantity to justify construction of a transmission line to the area. And yet, many of the location-constrained renewable energy resources in the state will need to have their expected aggregate transmission needs included in overall transmission grid planning. The CPUC is taking steps to change the planning process in proceedings mandated by Senate Bill 1038 (SB 1038, Chapter 515, Statutes of 2002, Sher).

Inter-utility transmission congestion poses a challenge for the RPS because there is a mismatch between the location of abundant, cost-effective renewables and unmet RPS requirements. One policy option that may facilitate transactions between utilities confronted with transmission congestion between the supply and demand for renewable energy is unbundled renewable energy certificates (RECs) (i.e., separation of the "renewable attributes" from electricity generation). In California, unbundled RECs are not currently accepted for compliance with the RPS for the IOUs. Part of the reason for this decision is the absence of a clear showing that their use would be consistent with the specific goals of Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher) (e.g., public health, economic development, job creation, environmental, and other benefits anticipated by the statute). This white paper discusses the current status of public discussion on the challenges and opportunities related to possible use of unbundled RECs in California's RPS program at a future date.

Other issues that may affect accelerated central-station renewable energy development include adequacy of public goods charge funds and integration of intermittent renewables. The staff will not know the results of the first formal RPS solicitations and their implications for public goods charge fund adequacy until the end of 2004. As a result, further discussion of these two issues is planned for the 2005 *Energy Report*.

Regarding renewable distributed generation, this white paper discusses recent trends, outlooks, and policy issues related to California's incentive programs for distributed photovoltaic generation and the Governor's interest in expanded development of photovoltaic systems in new homes.[4] The 2005 *Energy Report* will contain an expanded discussion of distributed generation issues based on ongoing collaborative work between the CPUC and the Energy Commission in this area.

Next Steps

The staff has prepared this white paper to further public discussion regarding accelerated renewable energy development to meet California's growing electricity retail sales. The Energy Commission's Integrated Energy Policy Report and Renewables Committees expect to hold workshops this summer to request additional information and input from stakeholders and the general public regarding the trends and key policy issues raised in this paper. Results from the workshops will be used to inform Committee recommendations for the *2004 Energy Report Update*, and *2005 Energy Report*, as well as proceedings at the Energy Commission and CPUC on renewable central station and distributed generation resource development.

Notes

[1] See California Energy Commission*, Renewables Portfolio Standard Eligibility Guidebook*, 500-04-002F; California Energy Commission, *Renewables Portfolio Standard Overall Program Guidebook*, 500-04-026; and California Energy Commission, *New Renewable Facilities Program Guidebook, 500-04-001F.*
[2] *Under funds autho*rized by Senate Bill 90 (SB 90, Chapter 905, Statutes of 1997, Sher), which predated the RPS program.
[3] Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher).
[4] There are several kinds of renewable distributed generation besides photovoltaic energy. Other renewable distributed generation technologies will be discussed in the *2005 Energy Report*.

CHAPTER 1: INTRODUCTION

This draft staff white paper addresses specific policies related to accelerated renewable energy development in both central-station and distributed generation applications. Following the recommendations of the 2003 *Integrated Energy Policy Report (Energy Report)*, this white paper discusses the following key policy issues: post-2010 renewable energy goals, differential utility targets, possible use of unbundled renewable energy certificates in future years of the RPS, and key issues for renewable distributed generation, primarily distributed photovoltaic (PV) generation.

As part of the discussion of central-station renewables, this draft staff white paper highlights some of the key transmission-related challenges for renewable energy. Some concentrated areas of renewable energy potential are located far from existing transmission lines or would connect to transmission lines that are already fully utilized. The availability of transmission for these renewables is a barrier to renewable development in the state, but the staff has engaged stakeholders and sister agencies, including the California Public Utilities Commission (CPUC) and the California Independent System Operator (CA ISO), to consider alternative approaches to transmission planning processes. As part of the work for the *2004 Energy Report Update,* a number of workshops have been held on transmission issues and staff has prepared a white paper focusing on transmission. The transmission white paper will discuss renewable transmission interconnection issues in more depth than this draft staff white paper.

Legislative and Policy Background

In 2002, the Legislature passed Senate Bill 1389 (SB 1389, Chapter 568, Statutes of 2002, Bowen) requiring the California Energy Commission (Energy Commission) to prepare and adopt a biennial *Energy Report*. SB 1389 also requires the Energy Commission to prepare an energy policy review to update analyses from the *Energy Report* or to raise energy issues that have emerged since its publication. This draft staff white paper has been developed as part of the preparatory record for the 2004 update to the 2003 *Energy Report*.

Also in 2002, the Legislature passed Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher) creating California’s RPS program. The law assigns administration of the RPS to the CPUC and the Energy Commission. The RPS program requires investor-owned utilities (IOUs), electric service providers (ESPs), and community choice aggregators (CCAs) to increase their sales of electricity from renewable energy by at least 1 percent per year, achieving 20 percent by 2017 at the latest, within certain cost constraints.

SB 1078 also contains RPS requirements for publicly owned electric utilities, specifically:

> Each governing body of a local publicly owned electric utility, as defined in Section 9604, shall be responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.

The Energy Commission, the Consumer Power and Conservation Financing Authority, and the CPUC adopted the *Energy Action Plan* in the spring of 2003. The plan establishes shared goals and specific actions to ensure that adequate, reliable, and reasonably priced electrical power and natural gas supplies are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.[1] One of the goals of the *Energy Action Plan* was to accelerate the state's goal of reaching 20 percent renewables from 2017 to 2010.[2]

During the 2003 recall election, Arnold Schwarzenegger's campaign website called for accelerating implementation of the RPS, to reach 20 percent renewables by 2010, rather than 2017, and set the state on course to derive 33 percent of its power from renewable sources by 2020.[3] Since taking office, Governor Schwarzenegger has repeated his call to accelerate phase-in of the RPS to reach 20 percent by 2010 and has called to encourage builders to build homes using partial solar power.[4]

Publicly owned electric utilities have RPS programs, with varying target levels, years, and definitions of qualifying renewable energy. Most publicly owned electric utilities have adopted RPS programs to reach 20 percent renewable energy by 2017, and include existing large hydroelectric power among the qualifying renewable energy resources. This reduces the significance of the 20 percent target for development of new renewable energy to meet growing electricity retail sales in California.

The following section discusses the scope of this white paper. It clarifies the renewable energy topics that are the focus of this paper, and the topics that are considered elsewhere. The section also provides references for resources on renewable energy topics that are not discussed in this paper.

Scope of Staff White Paper

This staff white paper discusses renewable energy as part of the preferred ordering of options for meeting California's electricity needs: energy efficiency, renewables and distributed generation, and gas-fired generation. This is referred to as the "loading order" in the *Energy Action Plan*, the *2003 Energy Report*, and Governor

Schwarzenegger's letter to CPUC President Peevey, which called on the CPUC to fully implement Assembly Bill 57 (AB 57, Chapter 835, Statutes of 2002, Wright).[5] AB 57 requires changes in the IOU electricity procurement process.

This white paper discusses trends and outlooks for renewable energy, selected policy issues for central-station renewable development, and key policy issues for renewable distributed generation, primarily distributed PV generation. It paper focuses on two key policy issues for central-station renewable energy: post-2010 goals and utility-specific RPS targets. Other central-station issues include the possibility of using unbundled renewable energy certificates in future RPS solicitations, and publicly owned electric utilities' RPS plans and activities.

The *Energy Action Plan* and the *2003 Energy Report* began a new collaboration between the Energy Commission and the CPUC regarding distributed generation. This white paper discusses issues related to extending the RPS to renewable distributed generation and possible restructuring of other incentives for distributed PV generation.

This white paper has been prepared to support the *2004 Energy Report Update* proceeding. This paper provides background information regarding the estimated energy and incentive levels available from key renewable energy programs in California, including RPS programs, and distributed PV generation commercialization programs. Issues on PV were selected because they are related to the Governor's call to encourage builders to build homes using partial solar power.

Other Efforts Underway Affecting Renewable Energy

Regarding renewable distributed generation, a broader discussion of research, development, demonstration, and commercialization efforts is planned for the 2005 *Energy Report*. The report will include information from the Energy Commission's distributed generation proceeding (04-DIST-GEN-1), the CPUC proceeding regarding distributed generation and distributed energy resources (R.04-03-017), and the departing load portion of the direct access proceeding (R.02-02-011), and decisions regarding cost recovery surcharge exemption and charges. Additional details regarding the CPUC's Self-Generation Incentive Program for distributed generation are available in the following CPUC proceedings: R.98-07-037 and R.04-03-017 and will also be discussed in the *2005 Energy Report*.

Senate Bill 1038 (SB 1038, Chapter 515, Statutes of 2002, Sher) provides public goods charge funds to support the RPS and a number of other renewable energy incentives in California. In addition, Senate Bill 90 (SB 90, Chapter 905, Statutes of 1997, Sher) authorized a series of competitive auctions to award energy production incentives to new renewable energy projects. Auctions were held in 1998, 2000, and

2001. Rules have been established by the CPUC and the Energy Commission guiding the participation of projects with existing SB 90 awards in the RPS.

Further information regarding rules, eligibility, and guidelines for incentive support through the RPS program for IOUs is available through the Energy Commission's RPS proceeding (03-RPS-1078) and Renewable Energy Program update proceeding (02-REN-1038), and the CPUC's procurement proceeding (R.01-10-024) and renewables proceeding (R.04-04-026).

Regarding transmission planning, the accelerated RPS adds to existing challenges in California. This paper does not discuss transmission needs and constraints in-depth, other than to recognize their importance and highlight a few characteristics of renewable energy development that challenge the traditional transmission planning approach.

Transmission planning issues are discussed in depth in a parallel white paper prepared in support of the *2004 Energy Report Update*, including discussion of current critical transmission projects for renewable energy, such as the Tehachapi area, and the results of public input from a number of workshops. The transmission white paper also identifies a number of renewable-related issues to be considered in the *2005 Energy Report*. Additional information regarding transmission planning with respect to renewable energy is available in the CPUC's transmission proceeding (I.00-11-001).

This paper discusses "active" generation of electricity from renewable resources. Some types of renewable resources, such as solar, can be used to heat or cool buildings through "passive" energy-efficient design features.[6] For more information, please see the Energy Commission's Rulemaking Proceeding for the 2005 Building Energy Efficiency Standards (Docket 03-BSTD-1).

Other important issues addressed in this white paper include activities beyond California borders. Outside of California, a number of regional and intra-state activities affect the development of renewable energy to meet California's electricity retail sales, including the Western Governors' Association target of 30,000 megawatts (MW) of "clean energy" by 2020. Another regional initiative is the West Coast Governors Climate Change Initiative. These initiatives were not highlighted in the *2003 Energy Report* as a focus for the *2004 Energy Report Update*, but are covered in detail by the Western Governors' Association and the Offices of the Governors of California, Oregon, and Washington.[7]

The following section sets forth the development process for this white paper.

Staff White Paper Development Process

The Energy Commission's 2004-2005 Integrated Energy Policy Report (IEPR) Committee held a public workshop to solicit public input on accelerated renewable energy development on May 4, 2004. At the May 4, 2004 workshop, stakeholders provided valuable comments regarding the RPS goals beyond 2010, possible re-calibration of specific utility goals, the RPS as it applies to publicly owned electric utilities, and unbundled renewable energy certificates (RECs).

On June 8, 2004, the IEPR Committee and the Renewable Committee jointly held a workshop on policies for distributed PV generation. Public comments from the May 4 and June 8, 2004 committee workshops are summarized in Appendix C. In addition, Appendix D discusses public comment received on the role of distributed generation in meeting the RPS. These comments responded to the "CPUC and Energy Commission Collaborative Staff Data Request," dated October 20, 2003.

Following the publication of this staff white paper, the IEPR and Renewables Committees will hold public workshops or hearings to solicit public input. The IEPR Committee and the Renewables Committee will consider comments received in response to the workshops or hearings in preparing its *2004 Energy Report Update* recommendations regarding renewable energy goals.

This staff white paper draws on publicly available information regarding renewable energy development in California, including the collaborative CPUC and Energy Commission RPS proceedings, the CPUC transmission proceeding as it relates to renewable energy, Western Renewable Energy Generation Information System (WREGIS) decisions and progress to date, investigation of possible development activities regarding PV energy systems on new homes, and the collaborative CPUC and Energy Commission proceedings regarding distributed generation.

Key Assumptions and Definitions

For analysis purposes, this paper assumes that the accelerated renewable energy development target of 20 percent by 2010 applies to retail sales of energy in California statewide. The term "retail sales" refers to the energy that is sold to end-use customers and measured at the customer's meter. For this analysis, the 20 percent by 2010 target applies to all load serving entities, including IOUs, ESPs, CCAs, and publicly owned electric utilities.[8]

For planning purposes, the staff estimates focus on a statewide goal of 20 percent by 2010. Appendix A contains details for these estimates. Following SB 1078's approach to reaching 20 percent renewables (i.e., at least 1 percent per year until 20 percent is reached), the staff estimates assume that each retail seller and publicly owned electric utility will procure at least one additional percent per year of renewable energy. If the one percent per year increase does not result in 20 percent by 2010, then the estimate presumes that the utility must procure at a greater rate until the 20 percent by 2010 target is reached. Also, it assumes that the 2001 and 2003 baseline renewable energy amounts continue to be procured each year by the same retail seller and at the same amounts. In addition, this estimate assumes that the ESPs, CCAs, and publicly owned electric utilities achieve 20 percent renewables by 2010 using the definitions of eligible renewable energy in SB 1038 and SB 1078.

Provided that additional criteria specified in SB 1038, SB 1078, and the RPS guidebooks are met, central station or distributed generation facilities using the following resources are likely to be eligible for the RPS:[9]

- Biomass: any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing and construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, and wood and wood waste from timbering operations.
- Solar thermal electric: the conversion of sunlight to heat and its concentration and use to power a generator to produce electricity.
- PV: a technology that uses a semiconductor to convert sunlight directly into electricity.
- Wind: energy from wind converted into mechanical energy and then electricity.
- Geothermal: natural heat from within the earth, captured for production of electric power, space heating, or industrial steam.
- Fuel cells using renewable fuels: an advanced energy conversion device that combines hydrogen-bearing fuels with air-borne oxygen in an electrochemical reaction to produce electricity very efficiently and with minimal environmental impact.
- Small hydroelectric generation of 30 MW or less: a facility employing one or more hydroelectric turbine generators, the sum capacity of which does not exceed 30 MW.
- Digester gas: gas from the anaerobic digestion of organic wastes.
- Municipal solid waste conversion: solid waste as defined in Public Resources Code section 40191.
- Landfill gas: gas produced by the breakdown of organic matter in a landfill (composed primarily of methane and carbon dioxide) or the technology that uses this gas to produce power.
- Ocean wave: refers to an experimental technology that uses ocean waves to produce electricity.
- Ocean thermal: refers to an experimental technology that uses the temperature differences between deep and surface ocean water to produce electricity.
- Tidal current: energy obtained by using the motion of the tides to run water turbines that drive electric generators.

For some resource types, RPS eligibility is contingent upon the type of fuel used, environmental impacts (e.g., does not require a new appropriation of water), whether/when a facility was owned by an IOU, and/or date of commencing commercial operations, among other criteria. For details regarding RPS eligibility please see the *Renewables Portfolio Standard Eligibility Guidebook*.

In addition to those resources currently eligible for RPS, this paper addresses distributed generation renewable resources eligible for incentive programs in California, focusing on PV systems. Distributed generation is defined as electricity that is generated on-site or near the place of use, typically ranging in capacity from 3 to 10,000 kilowatts (kW). Rules for the participation of renewable distributed generation in California's RPS are not yet defined.

As the RPS is measured in terms of retail sales of energy rather than renewable generation capacity, most of the information in this paper is presented in the units of gigawatt hour per year (GWh/year).

A term used in this report, but perhaps not known to the reader is REC. A REC represents the renewable or "green" attributes of the electricity produced from renewable resources. A REC may be "bundled" with the underlying electricity or sold separately ("unbundled"). If a REC is unbundled from its associated energy, it is often termed a "Tradeable REC."

Another term that may be unfamiliar is "net metering." The term refers to an arrangement with an electric utility that allows the PV owner's electricity meter to spin backwards when the PV system is generating electricity and spin forward when the owner is drawing electricity from the grid (e.g., at night). At the end of a 12-month period, there is a balancing of the account. If the PV owner has used more electricity than the PV system generated, the PV owner pays the utility for the electricity. If the PV owner has used less electricity than the PV system generated, the account is reset to zero for the next 12-month period. This is unfair to those who generate more electricity than they use, but provides an incentive to match the size of distributed PV generation systems to the on-site load.

Organization of White Paper

The remainder of the white paper is organized into the following chapters:

- Background
- Trends and Outlook
- Policy Issues for Central-station Renewables Development
- Key Policy Issues for Distributed Generation PV Energy Systems

Notes

[1] California Energy Commission, California Public Utilities Commission, and California Power Authority, *Energy Action Plan*, [http://www.energy.ca.gov/energy_action_plan/index.html], accessed July 15, 2004.
[2] The accelerated RPS goal adopted in the Energy Action Plan is incorporated in the CPUC Order Instituting Rulemaking 04-04-026. The RPS rulemaking states, "…we encourage the utilities to procure cost-effective renewable generation in excess of their [annual procurement targets] for this year, in order to make progress towards the goal expressed in the [Energy Action Plan]."
[3] "Arnold's Agenda to Bring California Back," 2003, [http://www.joinarnold.com/en/agenda/], accessed July 24, 2004.
[4] Regarding accelerating the RPS to 20 percent by 2010, see Office of the Governor of California, April 28, 2004, "Press Release: Governor Schwarzenegger Announces Electricity Priorities," [http://www.governor.ca.gov/state/govsite/gov_pressroom_main.jsp], accessed July 15, 2004. Regarding encouraging PV in new homes, see "Governor Schwarzenegger's State of the State Address," January 6, 2004, [http://www.governor.ca.gov/state/govsite/gov_homepage.jsp], accessed July 15, 2004.
[5] Governor Arnold Schwarzenegger, April 28, 2004, Letter to the Honorable Michael R. Peevey, President, Public Utilities Commission, [http://www.governor.ca.gov/govsite/pdf/press_release/PUC_Letter.pdf], accessed July 27, 2004.
[6] Passive solar is used to describe how solar building designs and materials can provide cooling and heating to keep a home comfortable and energy efficient without the use of mechanical equipment. Careful site selection and planning, selection of construction materials and other building features are a must. It represents an area with significant potential for saving money on utility bills. Some research has shown passive solar design and construction strategies can help homeowners reduce utility bills by 10 to 40 percent — best when incorporated in initial planning and design — or with minimal increase in renovation costs where remodeling existing homes. Title 24 building standards address these and related energy efficiency design features.
[7] The Western Governors' Association clean energy initiative includes support for renewable energy, energy efficiency, clean coal, and advanced natural gas technologies. Clean coal technologies refer to four types of innovations (i.e., environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications) to reduce the environmental impacts of coal. Western Governors' Association, June 22, 2004, "WGA Policy Resolution 04-15: Clean and Diversified Energy Initiative for the West." [http://www.westgov.org/wga/policy/04/clean-energy.pdf], accessed July 7, 2004. See also U.S. Department of Energy, National Energy Technology Laboratory, "Clean Coal Technology Program," [http://www.netl.doe.gov/cctc/programs/program.html], accessed July 14, 2004. For further information regarding the west coast governors' initiative on climate change,

see Office of the Governors of California, Oregon, and Washington, "West Coast Governors' Global Warming Initiative," [http://www.ef.org/westcoastclimate/], accessed July 16, 2004.

[8] As discussed above, SB 1078 directs the publicly owned electric utilities to develop RPS programs consistent with the intent of the legislature, taking costs and the goal of environmental improvement into account. The *2003 Energy Report* recommended that the RPS be mandatory for all retail sellers, including publicly owned electric utilities.

[9] See Energy Commission*, Renewables Portfolio Standard Eligibility Guidebook*, 500-04-002F; Energy Commission, *Renewables Portfolio Standard Overall Program Guidebook*, 500-04-026; and Energy Commission, *New Renewable Facilities Program Guidebook*, 500-04-001F.

CHAPTER 2: BACKGROUND

This chapter provides background information regarding the RPS procurement process and incentive programs for renewable distributed generation.

The CPUC and the Energy Commission have set up a collaborative process to implement the RPS program. While SB 1078 sets out clear tasks for each agency, the two agencies are working closely together to ensure smooth coordination of the various aspects of the program.

CPUC decisions regarding the topics under their jurisdiction are available in the following CPUC proceedings: R. 01-10-024 and R.04-04-026.

The Energy Commission has adopted Guidelines to implement the RPS as described in three documents:

- *Renewables Portfolio Standard Eligibility Guidebook*,
- *Overall Program Guidebook for the Renewable Energy Program*, and
- *New Renewable Facilities Program Guidebook*. [1]

These guidebooks are periodically updated as needed.

Publicly owned electric utilities are developing plans for their own RPS programs. Chapter 3 discusses their on-line renewable energy resources and RPS programs.

Renewables Portfolio Standard Procurement Process for Central-station Renewables

This section contains a brief overview of the RPS procurement process for IOUs as outlined in RPS legislation, decisions, and guidebooks. RPS rules are not yet in place for ESPs or CCAs.[2]

Appendix B contains additional details regarding rules for participating in RPS solicitations held by IOUs including the following topics:

- Annual Procurement Targets
- IOU Request for Offers to Meet RPS Obligations
- Market Price Referent
- Bid Evaluation — IOU Selection of Least-Cost-Best-Fit Bids
- Integration Costs
- Transmission Costs
- Other Considerations in Bid Evaluation
- Disclosure of Market Price Referents
- Bids above the Market Price Referent — Supplemental Energy Payments

- Applying for Certification and Pre-Certification
- Eligibility for Supplemental Energy Payments
- Rules that Apply when a Bidder has an SB 90 Award
- Multiple Awards
- Tracking Progress

The RPS legislation directs the IOUs to hold competitive solicitations to procure RPS eligible energy. In holding these solicitations, the IOUs must follow the guidance and rules put forward in law and implemented by the Energy Commission and the CPUC. The introduction contains references to CPUC and Energy Commission decisions on rules for the RPS.

Following direction from the CPUC, the utilities held “interim” solicitations in 2002 and Southern California Edison (SCE) held a second interim solicitation in 2003 in advance of the first formal RPS solicitations. The contracts resulting from the 2002 solicitations count towards the utilities’ annual procurement target requirements for the RPS.[3] SCE’s 2003 solicitation is expected to result in contracts that will count towards the RPS, but no contract agreements have been publicly announced as of July 2004. Also, the utilities entered into bilateral contracts from 2002-2004 to procure energy that would qualify for the RPS.

The formal rules needed to implement the legislative requirements for the three major IOUs are complete, allowing Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric (SDG&E) to release their first formal RPS solicitations in July 2004. As experience with formal RPS solicitations accumulates, RPS rules will be adjusted as necessary to accommodate lessons learned and ongoing data refinements.

It should be noted that SCE procured sufficient quantities of renewable energy through the interim solicitations for the CPUC to approve its request to forgo a 2004 RPS solicitation. SCE claims it will reach 20 percent renewables in 2004.

The CPUC sets the amount of eligible renewable energy that each IOU must procure annually, the “annual procurement target.” Additionally, the CPUC identifies the amount the IOU must procure to increase its renewable resources by at least 1 percent of its retail sales per year. IOUs have some flexibility as to whether they meet the full annual procurement target in advance, during, or subsequent to the year it applies.

Any facility operator interested in contracting with an IOU to deliver RPS-eligible electricity must request the Energy Commission to certify that the project is eligible. The Energy Commission also certifies facilities as eligible for both the RPS and Supplemental Energy Payments (SEPs), described below.

In applying for certification, the facility operator, or the IOU on the operator’s behalf, agrees to participate in the Energy Commission’s generation tracking system. The generation from facilities certified as eligible for the RPS may be claimed by the procuring IOU for purposes of meeting its RPS requirements.

For each competitive bid solicitation, the IOUs evaluate the bids and select those that best meet their current needs at the lowest cost, based on a process consistent with the CPUC's decisions on least-cost-best-fit issues. As part of the process, the IOUs add to the bid price an estimate of transmission and integration costs, but only for the purpose of ranking bids. The IOU, with confidential oversight from representatives of non-market organizations, selects the winners from the solicitation and requests contract approval from the CPUC.

The winning bidder and utility must abide by standard contract terms and conditions established by the CPUC. The IOU will count the generation procured towards meeting its RPS obligations once the energy is generated and delivered. The Energy Commission tracks and verifies RPS eligible transactions.

Winning bidders representing new or repowered facilities may be eligible for SEPs from the Energy Commission. The SEP award is partly a function of the market price referent (MPR) calculated by the CPUC. The MPR represents a proxy for the cost of a comparable, long-term contract with a natural gas facility, levelized into a cent-per-kWh value. The MPR also represents a dividing line:

- Bid prices at or below the MPR may be accepted as *per se* reasonable to the CPUC;

- Bids priced above the MPR may be eligible for SEPs to cover the difference between the MPR and the bid price, subject to funding availability and subject to Energy Commission determination.

The Energy Commission awards SEPs, providing a supplemental revenue stream to the generator for up to 10 years. SEPs are funded from the public goods charge. Bilateral contracts are not eligible for SEPs, but the CPUC "will allow prudent bilateral contracts only when such contracts do not require any public goods charge funds."[4] The CPUC calculates the MPR before it sees any bid prices, and the MPR is publicly released after the utility selects a "short list" of potential winners among the bidders.

The next section provides an overview of current incentive and research programs related to distributed PV generation. Possible changes to distributed PV generation incentive programs, such as performance-based incentives and policy options to encourage the use of PV in new homes, are discussed in Chapter 5. Changes in these programs are likely to affect implementation of the RPS for renewable distributed generation.

Incentive Programs for Renewable Distributed Generation in California

Renewable distributed generation allows consumers to develop their own supply of electricity. This form of electricity generation meets a very small proportion of California's electricity load, but is growing quickly. Depending on its placement relative to transmission and distribution congestion, renewable distributed generation has the potential to provide benefits to the electric system by providing electricity to the grid during periods of peak demand.

The CPUC, the Energy Commission, the California Power Authority, and numerous publicly owned electric utilities are working to ensure California distributed generation policy is in place to encourage electricity customers to become customer generators. This section provides an overview of the programs in California to support commercialization, research, and development of renewable distributed generation.

The Energy Commission's Emerging Renewables Program began offering cash rebates for "emerging" renewable systems in March 1998. Emerging renewable systems include PV, wind, solar thermal and renewable fuel cells. While the funding levels and rebates offered have varied over the last several years, the Emerging Renewables Program has helped install over 36 MW of renewable distributed generation, most of it PV, in the service territories of PG&E, SCE, and SDG&E.

Launched in July 2001, the CPUC's Self-Generation Incentive Program provides $125 million per year to offset costs of grid-connected distributed generation systems for customers of any of the following IOUs: PG&E, SCE, SDG&E, or Southern California Gas. The program is funded through the normal operating budget of the IOUs and future rates will be adjusted to cover the expenses. Systems must be between 30 kW and 1 MW in size. To date, the Self-Generation Incentive Program has helped install 18 MW of PV.[5] Eligible technologies include PVs, wind turbines, fuel cells, microturbines, small gas turbines and internal combustion engines.[6]

Several publicly owned electric utilities offer incentive programs for distributed PV generation. Table 1 below details the publicly owned electric utility and the amount of grid-connected PV that is installed in their service territories.

Table 1. Amount of Grid-Connected PV Installed in Publicly Owned Electric Utility Service Territories

Publicly Owned Electric Utility	kW of Grid-Connected PV
Alameda	5
Anaheim	296
Burbank	7
Glendale	19
Lodi	4
Los Angeles	9,509
Palo Alto	266
Pasadena	84
Redding	8
Riverside	389
Roseville	115
Sacramento	11,410
Santa Clara	54
Ukiah	20
Total	22,186

Sacramento and Los Angeles have the largest programs. The sum of the other publicly owned electric utility programs is about one-eighth the size of the Los Angeles program, measured by cumulative grid-connected PV capacity installed as of June 30, 2004.[7] Cumulative installed PV capacity is about 80 MW in California and is reported in further detail in the trends and outlook chapter.

The rebate programs discussed above are funded through public goods fund charge funds.[8] California and federal taxpayers also support distributed PV generation through the respective tax credits. For 2004 and 2006 tax years, the state tax credit is 7.5 percent of net system costs (or $4.50 per rated watt, whichever is less). For businesses, a federal tax credit of 10 percent is also available. Businesses may also depreciate the cost of PV systems as part of their state and federal taxes. Table 2 provides an example of the way the tax credits and depreciation complement the capital cost rebates to reduce the cost of a grid-connected PV system.[9]

Table 2. Sample PV System Costs after Tax Credits and Rebate

EXAMPLE: Residential Installation	
Total System Size	**2.4 KW AC**
Total Installed System Cost	$19,200.00
California State Rebate ($3.20/watt)	– $7,680.00
Net Installed System Cost	$11,520.00
7.5 % CA Tax Credit (all in year 1 or spread over 7 years)	– $864.00
Cost to the PV system owner (in year 1)	**$10,656.00**
EXAMPLE: Commercial Installation	
Total System Size	**25 KW AC**
Total Installed System Cost	$ 175,000.00
California State Rebate ($3.20/watt)	– $ 80,000.00
Federal 10 % Investment Tax Credit (businesses only)	– $ 9,500.00
Net Installed System Cost	$85,500.00
7.5 % Tax Credit (all in year 1 or spread over 7 years)	– $6,41 2.50
5-Year Federal Accelerated Depreciation Savings (34 % tax rate)	– $30,685.00
State Depreciation Savings (6.5 % tax rate)	– $5,758.20
Cost to the PV owner (in year 6 after final depreciation)	**$42,644.30**

Source: California Energy Commission, “Solar or Wind Energy System Credit Fact Sheet: Updated for 2004 Tax Year, ”[http://www.energy.ca.gov/renewables/documents/SOLAR_WIND_TAX_CREDIT.PDF].

In addition to rebate programs and tax credits, low-interest loans are available to support customer purchases of distributed PV generation. The Energy Commission provides low-interest loans for installing energy efficiency projects under the Energy Conservation Assistance Account and Local Jurisdiction Energy Assistance Account. Projects with proven energy and/or capacity savings are eligible, including renewable energy projects. Solar PV and passive solar systems are among the eligible systems receiving energy efficiency financing. Loans are available up to $3 million per application and are available to cities, counties, special districts, public and non-profit schools, public care institutions and hospitals. The interest rate is 3.95 percent and is fixed for the term of the loan. The Energy Commission will offer a lower interest rate of 3.85 percent for those who complete the project and invoice the Energy Commission within nine months of the date the loan is approved at an Energy Commission Business Meeting.

Support for commercialization and installation of renewable energy is only one part of efforts to accelerate renewable energy development in the state. Research and development is another. A number of research activities and programs are underway at the IOUs, research universities, and the Energy Commission. Federal funding for research and development of renewable energy is also a critical complement to these activities. The *2005 Energy Report* will discuss research and development on these topics. Also, see the *Public Interest Energy Research: 2003 Annual Report*.[10]

In the coming months, the collaborative RPS staff of the CPUC and the Energy Commission will be developing rules for the participation of renewable distributed generation in the RPS. The following section provides background on the issues associated with this topic. Appendix D summarizes public comments.

Incorporating Renewable Distributed Generation into the Renewables Portfolio Standard

The CPUC first raised the issue of how to integrate PV generation into the RPS in Decision 02-10-062, which states:

> Including renewable distributed generation as part of our definition [of eligible renewable generation] will serve to encourage its installation, regardless of whether the utility purchases the output or whether it serves to meet on-site load. The full output of renewable distributed generation should be credited to meeting the RPS or D.02-08-071 requirements, but only new renewable distributed generation installations are to be credited (existing renewable distributed generation does not count toward the utility's RPS calculation).

This statement recognizes the uniqueness of distributed generation and the state's interest in advancing its deployment, but the statement "should be credited" raised concerns in the market about the transfer of property rights potentially without compensation. The property rights in question are the RECs associated with the distributed generation output. RECs are discussed in further detail in Chapter 4.

A related issue is that distributed PV facilities are typically designed to meet on-site energy demands (e.g., residential systems are usually 2-4 kW; commercial applications range greatly, with the maximum size eligible for a rebate being 1,000 kW). As a result, distributed generation systems do not necessarily deliver electricity into the electricity grid. It is sometimes difficult to measure the amount of generation from distributed PV, as it may be metered differently than central-station facilities, or it may not be separately metered at all.

Renewable electricity that is used for the RPS but not delivered to the electricity grid could be thought of as crediting the renewable attributes of the electricity to the utility without delivering the electricity itself. As described in Chapter 4, this is called an unbundled REC. CPUC Decision 03-06-071 states that unbundled RECs are not eligible for the RPS program at this time. Clarification may be needed to reconcile the CPUC's decision on the ineligibility of unbundled RECs with its decision on integrating distributed PV into the RPS.

In addition, applying the RPS retroactively to existing renewable distributed generation would add a layer of complication to the RPS that does not appear to be warranted by the relatively small amount of existing renewable distributed generation. On the other hand, the California Power Authority has argued that existing distributed generation should be treated the same as existing central-station renewables, which would mean revising each IOU's RPS baseline to include existing renewable distributed generation.[11]

(As a side note relevant to incentives for PV, on-site generation is not eligible for SEPs through the RPS program. Incentives for PV are discussed in Chapter 5.)

This chapter provided background information on the rules and scope of the RPS and a brief overview of existing programs and levels of support for distributed PV generation in California. The next chapter discusses trends and outlooks related to activities of these programs to support accelerated renewable energy development to meet California's electricity retail sales.

Notes

[1] California Energy Commission, May 2004, *Renewables Portfolio Standard Eligibility Guidebook*, 500-04-002F, [http://www.energy.ca.gov/portfolio/ documents/index.html], accessed July 28, 2004. California Energy Commission, May 2004, *Renewables Portfolio Standard Overall Program Guidebook*, 500-04-026, [http://www.energy.ca.gov/portfolio/ documents/guidebooks/2004-06-08_500-04-026.PDF], accessed July 28, 2004. California Energy Commission, May 2004, *New Renewable Facilities Program Guidebook*, 500-04-001F, [http://www.energy.ca.gov/ portfolio/ documents/2004-05-10_500-04-001F.PDF], accessed July 28, 2004.

[2] Similar to the IOUs, ESPs and CCAs are subject to the RPS. ESPs currently make up about 10 percent of the retail load in California. CCAs may become an attractive alternative that has not yet been implemented in the market. The California Energy Commission and the CPUC plan to develop implementation rules for these retail providers in the next phase of the RPS program. The rules for these retail providers will need to reconcile the legislative intent to develop long-term contracts for renewable power, and the short-term procurement structure of this market.

[3] CPUC, August 13, 2003, "Assigned Commissioner's Ruling Specifying Criteria for Interim Renewable Energy Solicitations (R.01-10-024), [http://www.cpuc.ca.gov/PUBLISHED/RULINGS/28681.htm], accessed July 18, 2004.

[4] CPUC, Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program, Decision 03-06-071, June 19, 2003.
[5] The SGIP reports that they have helped install over 21 MW of PV. However, PV installations that the SCGC reports are also reported by the electric utilities LADWP, Pasadena, and Anaheim. To avoid double counting, where PV systems are counted by two different entities, the electric utility is credited with the installation.
[6] California Public Utilities Commission, July 3, 2001, "CPUC Offers Incentives to Customers who install Self-Generation," Press Release, [http://ora.ca.gov/distgen/selfgen/sgips/], accessed July 16, 2004.
[7] California Energy Commission, updated June 21, 2004, "Grid-Connected PV Capacity (kW) Installed in California," [http://www.energy.ca.gov/renewables/emerging_renewables.html], accessed July 16, 2004.
[8] Public goods charges paid by IOU ratepayers are used in IOU service areas. Public goods charges paid by publicly owned electric utility ratepayers are used in their service areas.
[9] California Energy Commission, 2004, "Solar or Wind Energy System Credit Fact Sheet: Updated for 2004 Tax Year," [http://www.energy.ca.gov/renewables/documents/ SOLAR_WIND_TAX_CREDIT.PDF], accessed July 16, 2004. Notes for residential system example: rated peak generating capacity, measured in alternating current watts, considers the PTC rating and inverter efficiency, both of which reduce the system output. Actual rebate amounts will vary depending on system components and installation. Rebate levels are reduced about 5 percent every 6 months. Rebates subject to funding availability. Notes for commercial system example: Calculated as follows: (total installed system cost – state rebate – one-half of the 10 percent federal investment tax credit) x federal income tax rate. Estimate assumes a "non-corporate" business taxpayer who uses the modified accelerated cost recovery system. Please note that "corporate" business taxpayers may not use this method for California depreciation calculations and should instead use a 12-year recovery period. Calculated as follows: (total installed system cost – state rebate – 7.5 percent tax credit) x state income tax rate. Final costs will vary depending upon each taxpayer's individual situation and should be determined with the assistance of a qualified tax professional.
[10] California Energy Commission, March 2004, *Public Interest Energy Research: 2003 Annual Report*, 500-04-010, [http://www.energy.ca.gov/reports/2004-04-01_500-04-010.PDF], accessed July 27, 2004.
[11] Comments provided by the California Power Authority in response to the CPUC and Energy Commission Collaborative Staff Data Request: Inviting Comments on Renewable Distributed Generation in the Renewable Portfolio Standard Program. The data request was distributed on October 20, 2003.

CHAPTER 3: TRENDS AND OUTLOOK

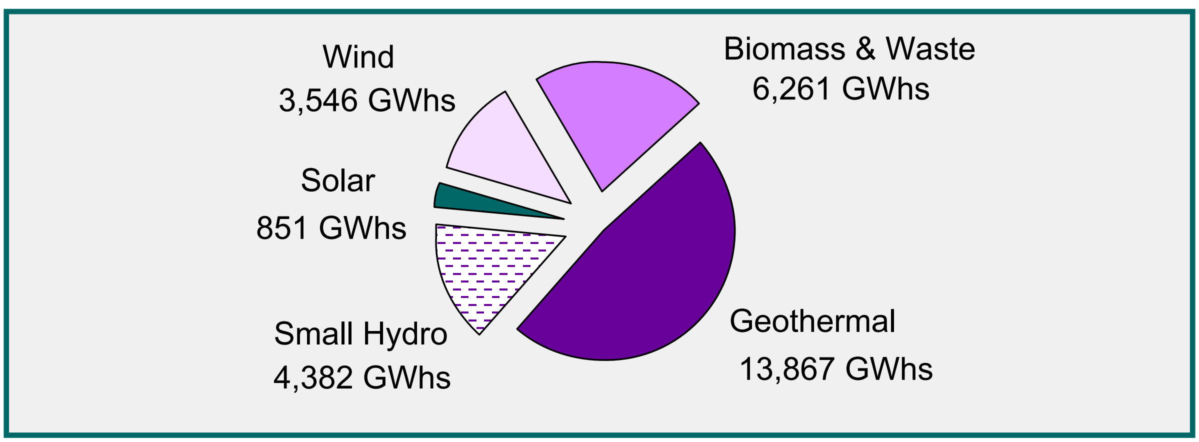
This chapter sets the context for the issues addressed in subsequent chapters related to central-station renewables and incentive programs for distributed PV generation to meet electricity needs in California. This chapter discusses the following topics:

- Existing central-station renewables
- Estimated energy needed to meet the accelerated RPS
- Distributed PV generation

At the end of 2002 (the latest year data is available), California had approximately 7,000 MW of installed renewables capacity. These 7,000 MW generated nearly 30,000 GWh of electricity (Figure 1), representing around 10 percent of electricity production used to serve California's electricity customers.

The RPS is measured by "sales." Until a more sophisticated tracking system is developed, the statewide renewable sales are estimated by the statewide renewable generation. Various "line losses" account for approximately seven percent of the generation, so the approximate 30,000 GWh of renewable generation results in roughly 26,000 GWh of renewable sales. A line loss can be defined as the electric energy lost (dissipated) in transmission and distribution lines as energy moves great distances from the generation location to the consumption location.

Figure 1. In-State Renewable Generation (2002) in GWh



Source: *Renewable Resources Development Report*, 2003.

Existing Central-Station Renewables

The renewable energy generated in California was sold by load serving entities to their end use customers. IOUs, ESPs, CCAs, and publicly owned electric utilities all sold renewable energy to their customers. The amounts and types of renewable sales are detailed below.

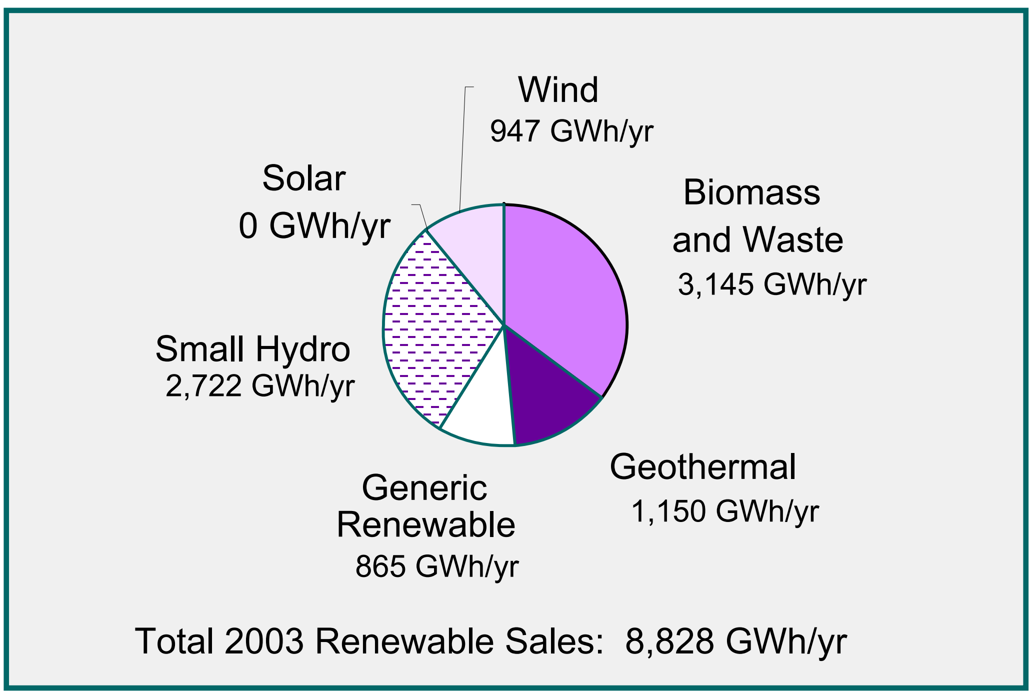
Investor-Owned Utilities

SB 1078 set 2001 as the initial renewable "baseline" from which compliance will be measured. Each year the RPS is in effect, the IOUs are required to increase their sales of "eligible" renewable energy by one percentage point, until 20 percent is reached. Each year a new "baseline" is set, upon which the one percentage point increase in eligible renewable energy is measured. The "eligible" renewables defined by SB 1038 have been noted above.

Pacific Gas and Electric Company

In 2003, PG&E reported that 12 percent of their electricity came from RPS-eligible renewable resources. This was a 3 percentage point increase over the 2001 baseline of 9 percent. On top of maintaining this new renewable baseline, PG&E will continue to add renewable energy until the 20 percent target is reached. Figure 2 details the renewable energy PG&E sold in 2003. For a description of Generic Renewable, please see the endnote identified in the title of this figure.

Figure 2. 2003 Renewable Sales for PG&E[1]

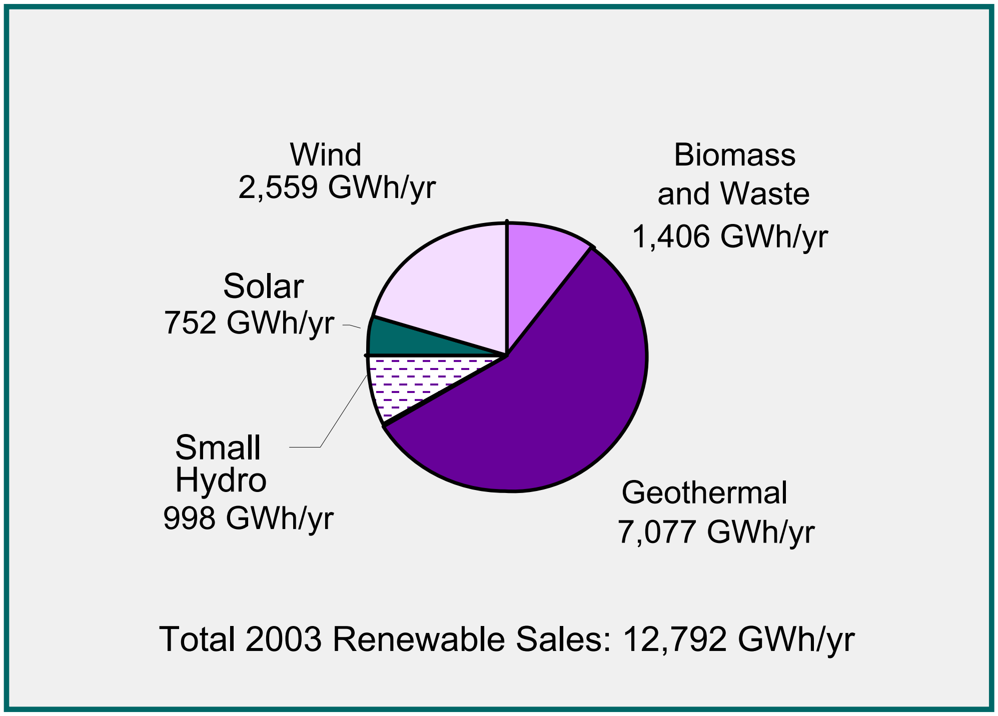


Source: Pacific Gas and Electric Company

Southern California Edison

In 2003, SCE indicated that 18 percent of its electricity came from renewable resources. This was a 3 percentage point increase over the 2001 baseline of 15 percent. Figure 3 details the renewable resources SCE sold in 2003.

Figure 3. 2003 Renewable Sales for SCE[2]

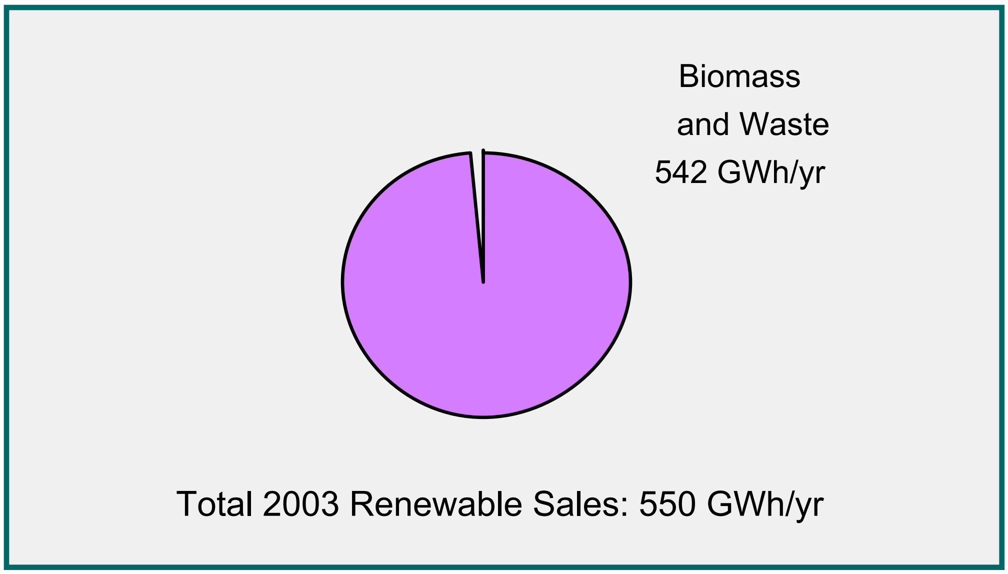


Source: Southern California Edison

San Diego Gas & Electric

Unlike SCE and PG&E, SDG&E does not currently have a diverse set of central-station renewable energy fuel sources. SDG&E indicates that about 4 percent of its electricity came from renewable resources (99 percent or 542 GWh/yr from biomass) in 2003. This was a 3 percentage point increase over the 2001 baseline of 1 percent.

Figure 4. 2003 Renewable Sales for SDG&E[3]



Source: Sempra Utilities

Publicly Owned Electric Utilities

In implementing and enforcing their own RPS programs, publicly owned electric utilities are not currently required to implement a 20 percent by 2010 plan and may pick the target year and percentage of renewables that best meet their needs, while considering rates, reliability, financial resources and environmental improvements.

The three major differences between the RPS as it applies to IOUs relative to publicly owned electric utilities are the ability of publicly owned electric utilities to determine their own percentage of renewables, timeframe for reaching that percentage, and fuel sources that qualify.

Unlike the IOUs, publicly owned electric utilities are allowed to determine which resources qualify as renewable for their RPS programs. IOUs are restricted to using the list of eligible renewables described earlier in this paper. Some publicly owned electric utilities limit themselves to the same resource list that IOUs use. Many add large hydroelectric power (> 30 MW) as a "qualifying" renewable resource. IOUs are allowed to count small hydroelectric (< 30 MW) as renewable, but are prevented from counting large hydroelectric power for their RPS programs.

While it is unlikely that new large hydroelectric power facilities will be built in California due to costs, including environmental, social, and cultural impacts, it is possible that publicly owned electric utilities may decide to purchase unbundled RECs from large hydroelectric power, possibly from the IOUs who are prohibited from using large hydro in their RPS programs. Further discussion of unbundled RECs is included in Chapter 4.

With such a degree of latitude, publicly owned electric utilities are designing and implementing vastly different plans, as highlighted below.

- The City of Alameda already has more than 50 percent of its sales come from eligible renewable resources. It has set a minimum renewable target of 40 percent and plans to maintain that target through 2020.

- The Sacramento Municipal Utility District (SMUD) has set a more accelerated target than SB 1078. SMUD plans to be at 10 percent eligible renewable by 2006 and 20 percent eligible renewable by 2011.

- The Los Angeles Department of Water and Power (LADWP) has recently adopted an RPS plan that mandates 20 percent by 2017, though the decision on how to count large hydro has not been settled.

- The Imperial Irrigation District (IID) has established a 20 percent by 2007 RPS. IID has stated that it intends to achieve its RPS by adding a geothermal plant by 2007.[4] IID considers the project renewable, and eligible for meeting its RPS obligation, although IID does not own the RECs associated with the electricity generated from the project.[5] Making a renewables market claim for electricity that is procured without RECs is contrary to the accounting approach for renewable energy endorsed by the Western Governors' Association. It is also contrary to California's Power Content Label Program.[6] This situation suggests a need for greater clarity regarding how to appropriately make renewable marketing claims in a REC market. Issues related to "green" tags and RECs are discussed in Chapter 4.

Several publicly owned electric utilities, including LADWP and SMUD, have recently issued solicitations for renewable energy.[7]

Table 3 lists individual publicly owned electric utilities, the amount of "eligible" renewables they currently have in their portfolio, the additional amount of "qualifying" renewables they currently have in their portfolio, whether they consider large hydroelectric to be a "qualifying" renewable resource, the renewable percentage target they plan to meet, and the date by which they plan to meet that target.

Table 3. Status and RPS Plans of Publicly Owned Electric Utilities[8]

Utility	Current renewable resources in utility portfolios (% of sales): "Eligible" Renewable*	Current renewable resources in utility portfolios (% of sales): Additional Large Hydro counted as a "qualifying renewable"	Large Hydro considered a "qualifying" renewable in RPS target?	Renewable portfolio target percent in the RPS plan?	Time frame for achieving the RPS target?
Alameda	50%	25%	Yes	40%	Maintain through 2020
Anaheim	<1%	1%	Yes	15%	2017
Azusa	7%	3%	Yes	20%	2017
Banning	0%	1.1%	Yes	20%	2017
Biggs	10%	Unknown	Yes	20%	Unknown
Burbank	1%	2%	"low impact"	20%	2017
Colton	2.2%	2.8%	Yes	15%	2017
Glendale	7.2%	7.4%	Yes	20%	2017
Gridley	10%	90%	Yes	20%	Unknown
Healdsburg	55%	Unknown			
Imperial[9]	12%	Unknown	Yes	20%	2007
Lodi	25%	21%	Yes	20%	Maintain for unspecified duration
Lompoc	37.3%	30.6%	Yes	20%	Purchases limited to available funds, load growth, and replacing retired resources
Los Angeles	1.5%	6.5 to 11.5%	Undecided.	20%	2017
Merced	11%	0	no	15%	2015
Modesto	<1%	Unknown	No	20%	2017
Palo Alto	3%	Unknown	Unknown	20%	2015
Pasadena	1.7%	5%	Yes	20%	2017
Plumas-Sierra Rural Electric Cooperative	Unknown	Unknown	Yes	20%	Unknown
Redding	4.8%	Unknown	Yes	20%	2017
Riverside	12%	1.5%	Yes	20%	2015
Roseville	14%	31%	yes	20%	Maintain for unspecified duration
Sacramento	7%	Unknown	No	20%	2011
Santa Clara	26%	39%	Yes	Intent: continue support of renewables.	
Trinity	0%	100%	Yes	Will "consider" only renewables in meeting future growth as additional needs grow beyond that provided by the Trinity River.	
Truckee Donner	Unknown	Unknown	Yes	Will seek to add qualifying renewables subject to public goods charge availability	
Turlock	8%	0	No	20%	2017
Ukiah	50%	30%	Yes	Will seek to add qualifying renewables as demand increases.	

Source: California Municipal Utilities Association, Publicly Owned Electric Utilities, and *Renewable Resources Development Report*, 2003

In 2001, publicly owned electric utilities bought over 7,600 GWh of large hydroelectric power. This comprised over one-third of all the large hydroelectric power used in the state. As publicly owned electric utilities seek to boost their renewable percentages, they may buy unbundled large hydroelectric RECs. Also, if publicly owned electric utilities buy large hydroelectric RECs, they may be willing to sell some of their existing "eligible" renewables to the IOUs, which may reduce the amount of new renewable energy procured by the IOUs to meet the RPS. If these two scenarios occur, this could greatly reduce the amount of new renewable projects built to satisfy the intent of the statewide RPS. This is contrary to the spirit of the RPS, the *2003 Energy Report*, and the *Energy Action Plan*, which aim to accelerate development of new renewable energy to meet the growing electricity retail sales in California.

Public Comments on Publicly Owned Electric Utilities' Renewables Portfolio Standard Programs

A number of stakeholders at the May 4, 2004 workshop commented verbally or in writing on how publicly owned electric utilities should implement the RPS. Many were in favor of mandating that the publicly owned electric utilities implement the same RPS as the IOUs, namely, 20 percent by 2010 without using large hydroelectric resources. A few were in favor of allowing publicly owned electric utilities flexibility in implementing their RPS programs or seeking an exemption because of their size and slow growth rates.

Those in favor of equal goals for all retail sellers of electricity include the Green Power Institute, the California Biomass Energy Alliance, PG&E, and Solargenix.

- The Green Power Institute and the California Biomass Energy Alliance argue that the Legislature intended the 20 percent renewable target to be a statewide target, and that any effort by the publicly owned electric utilities to procure less or use large hydro may lead to suspicions that they are attempting to avoid compliance.

- PG&E commented that the RPS should apply equally to IOUs and publicly owned electric utilities. PG&E stated that this was fundamentally an issue of fairness and equity. As renewables cost more in general, IOU ratepayers should not be forced to pay higher fees while publicly owned electric utility ratepayers are insulated because the publicly owned electric utilities choose not to comply with the RPS, as intended by the Legislature.

- Solargenix believes that publicly owned electric utilities should be required to spend a specified portion of the public goods charge funds on renewables and that they should comply with the same RPS standards as the IOUs. If need be, Solargenix argues, publicly owned electric utilities should aggregate their sales, similar to what the Northern California Power Authority or the Southern California Public Power Authority does.

Those in favor of granting local publicly owned electric utilities some flexibility include the California Municipal Utility Association (CMUA), SDG&E, and the Valley Electric Association.

- CMUA argued that, historically, publicly owned electric utilities have supported renewable energy, and that they continue to do so. CMUA was adamant, however, that their members retain the flexibility to interpret and enforce an RPS that best serves their local needs.
- SDG&E commented that several of the smaller publicly owned electric utilities may not have much growth in sales to phase in renewables, and that an exemption process should be established for them.
- The Valley Electric Association stated that complying with the RPS for their 32 California customers would be "impractical and cost-prohibitive." Valley Electric Association requested an exemption from the California RPS.

The staff agrees with the comments regarding setting a common percentage and timetable for IOUs and the publicly owned electric utilities. Also, the staff agrees that the definition of renewable energy for RPS purposes should be consistent throughout the state.

The staff agrees that an exemption should be granted for small utilities that face challenges complying with the RPS. As discussed below, the staff is exploring the possibility of using unbundled RECs in future RPS solicitations. If this option becomes available, it could reduce the need to grant exemptions for small utilities. Other mechanisms to accommodate the smaller public utilities should also be considered.

Next Steps on Publicly Owned Electric Utilities' Renewables Portfolio Standards

As stated above, one recommendation in the *2003 Energy Report* is that the state should enact legislation to require that all retail suppliers of electricity meet the RPS goal of 20 percent of retail electricity sales by 2010, including publicly owned electric utilities. Most publicly owned electric utilities include large hydroelectric power in their RPS programs, whereas the IOU RPS program does not.

To further the development of new renewable energy, the staff believes that publicly owned electric utilities should comply with the definitions of renewable energy found in SB 1038 and SB 1078.

Estimated Energy Needed to Meet the Accelerated Renewables Portfolio Standard

At the end of 2003, the staff estimates that there were 32,325 GWh of renewable energy sold by retail sellers in California. The following analysis assumes that all of that energy continues to be sold at the same levels as in 2003.

The staff estimates that in 2010, statewide electricity sales will total 285,399 GWh. To meet the accelerated RPS goal of 20 percent by 2010, California should have at least 57,079 GWh of renewable energy being sold in that year. Therefore, between 2004 and 2010, an additional 24,755 GWh/yr of renewable energy must come on-line and be sold by retail sellers in California to meet the accelerated RPS goal of 20 percent by 2010.

This estimate assumes that each IOU procures at least one additional percent per year of renewable energy. If this level is not procured, then the IOU must procure at a greater rate until the 20 percent target is reached. Also, it assumes that the 2001 and 2003 baseline renewable energy amounts continue to be procured each year by the same retail seller and at the same amounts. For example if the 2001 baseline is 14 percent, then the staff would assume that the 2003 procurement target was 15 percent, and 16 percent for 2004 and so forth.[10]

The staff developed its estimate prior to the CPUC adopting a methodology for calculating the annual procurement target, and as a result the two methodologies diverge slightly. The CPUC bases the 1 percent procurement requirement on the retail sales of the previous year (e.g. the 2004 annual procurement target is the 2003 baseline plus 1 percent of the 2003 retail sales).[11]

In addition, this estimate assumes that ESPs, CCAs, and publicly owned electric utilities comply with the RPS in the same fashion as the IOUs – namely, they reach 20 percent by 2010 and only include eligible renewables (i.e., large hydro is excluded).

For this white paper, the staff has updated these estimates based on more recent data, resulting in minor changes. The main revisions include adding historic data to the sales forecast, minor recalculating of the projected sales growth rate based on an updated forecast, and updating the amount of renewable energy the IOUs sold in 2001 and 2003. See Appendix A for the updated forecast and a current detailed breakdown of the estimated energy additions needed to meet the RPS in 2010 and 2017.

Table 4 identifies the estimated additional cumulative sales of renewable energy needed to achieve the statewide RPS goals defined in the *Energy Action Plan* (20 percent by 2010) and maintaining the same percentage of renewables until

2017. For this analysis, the amount of energy sold by ESPs and CCAs increases over time, but the percentage in relation to IOU sales remains roughly constant. These amounts are additions needed beyond 2001 baseline and estimated 2003 renewable sales. For details see Appendix A.[12]

Table 4. Estimated Statewide RPS Cumulative Additional Sales (GWh) to Meet 20 Percent by 2010 and Maintain 20 Percent through 2017

	2005	2008	2010	2017
Energy: GWh/year cumulative additions	5,540	17,579	24,755	30,586

Source: Appendix A.

Table 5 shows a further breakdown of the estimated additional energy from renewable resources needed to meet the statewide accelerated RPS, in addition to the estimated 2001 baseline energy and the estimated 2003 renewable sales. The 2001 and 2003 renewable estimates are based on CPUC filings submitted by the IOUs in 2003 and 2004, respectively.

Table 5. Estimated Cumulative Additional Sales (GWh) Needed After 2003 for Statewide Accelerated RPS

	2005	2008	2010	2017
PG&E				
Utility	855	4,695	7,322	8,989
ESP/CCA	366	857	1,211	1,386
SCE				
Utility	692	2,918	3,313	5,141
ESP/CCA	479	1,133	1,612	1,904
SDG&E				
Utility	722	1,999	2,893	3,302
ESP/CCA	141	339	489	609
Rest of State	2,285	5,637	7,915	9,256
Total New				
Utility	2,269	9,612	13,528	17,432
ESP/CCA	986	2,330	3,311	3,898
Rest of State	2,285	5,637	7,915	9,256
Grand Total	5,540	17,579	24,755	30,586

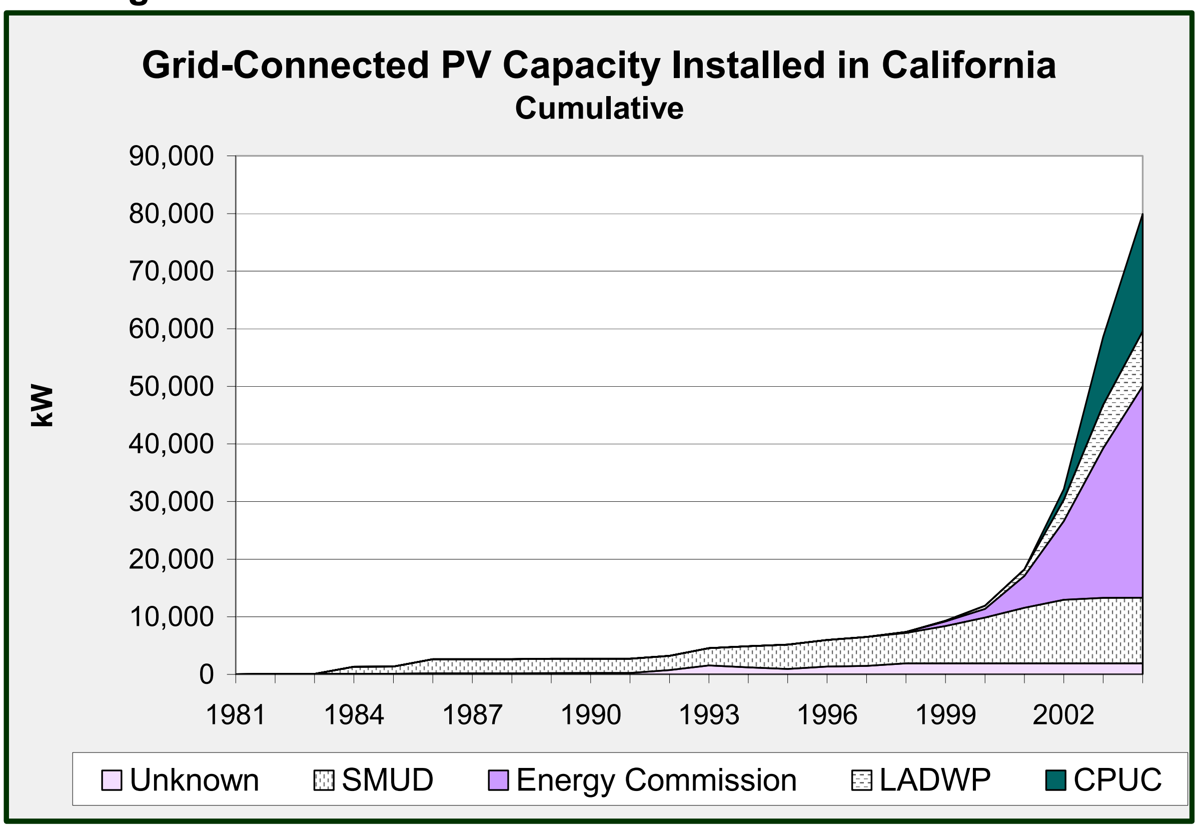
Source: Source: Appendix A

Distributed Photovoltaic Generation

Since the energy crises of 2000-2001, the installation of distributed PV generation systems has increased dramatically in California as shown in Figure 5. Before 2000, a mere 10 MW of grid-connected solar PV capacity had been installed in California; however, by 2003 California reached 60 MW of installed capacity and is currently above 80 MW of installed capacity. Residential and small commercial applications of renewable distributed generation systems in California are supported through several statewide incentives programs:

- The Energy Commission's Emerging Renewables Program (37 MW)
- The CPUC's Self-Generation Incentives Program, administered by the individual utilities (18 MW)
- The SMUD PV Pioneers Program (11 MW)
- The LADWP Solar Program (10 MW)

Figure 5. Growth in Grid-Connected Solar in California



Source: California Energy Commission, "Grid-Connected PV Capacity (kW) Installed in California," [http://www.energy.ca.gov/renewables/emerging_renewables.html], accessed July 16, 2004.

This chapter described the amount of central-station renewable energy currently used to meet the electricity retail sales in California. It indicated that at the end of

2003 that each of the IOUs has procured at least an additional two percentage points of renewables over their 2001 baseline. It also estimated that approximately 24,750 GWh/yr of renewable energy must be added to meet the statewide accelerated RPS of 20 percent by 2010. This chapter detailed how publicly owned electric utilities are implementing their various RPS programs. In general, the publicly owned electric utilities are establishing a 20 percent by 2017 target, but are choosing to include large hydroelectric power as a qualifying renewable resource. This chapter also reported the trends and outlook for PV distributed generation, which is a small but growing option for electricity consumers in California. As discussed in the background chapter, rules are not yet in place for the use of PV distributed generation in California's RPS.

The next chapter uses this information regarding the trends and outlooks as the basis for discussing key policy issues related to accelerated development of central-station renewable energy.

Notes

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[1] Pacific Gas & Electric, June 15, 2004, "Report to the California Energy Commission: Utility Procurement of Renewable Energy in 2003." "Generic Renewable" is the energy represented by PG&E's non-specific purchases. All of the individually labeled renewables were specifically purchased by PG&E. PG&E also bought generic power. Approximately 8 percent to 9 percent of the generic power is renewable. PG&E is claiming this as a separate part of its renewable purchases.

[2] Southern California Edison, June 22, 2004, "Report to the California Energy Commission: Utility Procurement of Renewable Energy in 2003."

[3] San Diego Gas & Electric, "Report to the California Energy Commission: Utility Procurement of Renewable Energy in 2003," June 17, 2004. Note: Solar and wind round to less than 1 percent.

[4] This is the Salton Sea VI project that has not yet sold IID RECs or the "green" tags associated with electricity generated from this facility. Currently, the developer is keeping the greenness and plans to sell the RECs on the open market; IID will only purchase the energy from the facility. IID is attempting to renegotiate the contract to gain control of the RECs.

[5] E-mail exchange between Todd Lieberg of the California Energy Commission, Glenn Steiger of IID and Jerry Jordan of the California Municipal Utility Association, July 9, 2004.

[6] While IID may plan on counting the electricity from this facility as renewable for its RPS program, it will be unable to do so on its Power Content Label, as mandated by Senate Bill 1305 (SB 1305, Chapter 796, Statutes of 1997, Sher). The Power Content Label Program requires all utilities that claim a specific resource mix to report the fuels they use. This information must be reported to their customers and to the California Energy Commission. The Power Content

Label Program requires that the RECs be included with the electricity claimed in the specific resource mix. It also excludes large hydroelectric power from the specific resource mix.

[7] Los Angeles Department of Water and Power, July 1, 2004, "LADWP Issues Request for Proposals for Renewable Energy Projects; Goal to Increase Renewable Power by 13 percent by 2010 and 20% by 2017," [http://www.ladwp.com/ladwp/cms/ladwp005938.jsp], accessed July 8, 04, and the Sacramento Municipal Utility District, June 16, 2004, "SMUD Looking for New Block of Renewable Power: Notification of Pending Solicitation for Renewable Power Purchase," [http://www.smud.org/news/releases/04archive/06_16_renewable.pdf], accessed July 8, 2004.

[8] This summary is compiled from information submitted by the California Municipal Utilities Association, data submitted in compliance with the Power Source Disclosure Program (SB 1305) and work done by the Lawrence Berkeley National Laboratory. For the most part, these values were provided by cities and utilities, and were not independently verified. "Eligible Renewable" is the same definition that IOUs must comply with to meet the RPS, as described in SB 1078 and SB 1038 (which excludes hydro facilities larger than 30 MW). "Qualifying Renewable" is usually the same set of resources that IOUs use to meet the RPS, but with the probable inclusion of large hydro (larger than 30 MW).

[9] IID has established a 20 percent by 2007 RPS. IID has stated that it intends to achieve its RPS with the addition of a geothermal plant by 2007. This is the Salton Sea VI project which has **not** sold IID the "green" tags. Rather, the developer is keeping the greenness and plans to sell the RECs to a third-party while IID only gets the energy. While IID is attempting to renegotiate the contract to gain control of the RECs, IID considers the project renewable, and eligible for its RPS, even without the RECs. From e-mail exchange between Todd Lieberg of the California Energy Commission, Glenn Steiger of the IID, and Jerry Jordan of the California Municipal Utility Association, July 9, 2004.

[10] Chapter 6 of the *Renewable Resources Development Report* goes into great detail regarding the amount of additional renewable electricity required to meet the statewide Renewables Portfolio Standard in 2017 and on an accelerated path in 2010. The report also details the methodology and assumptions used to derive those numbers.

[11] The CPUC adopted a methodology for developing the annual procurement target in its *Order Instituting Rulemaking*, Rulemaking 04-04-026, April 22, 2004. The CPUC refined the methodology in its *Opinion Adopting Standard Contract Terms and Conditions*, Decision 04-06-014, June 9, 2004.

[12] While the data for 2005 are slightly lower in this update than in the *Renewable Resources Development Report*, this can be attributed to the increased procurements made by the IOUs since 2001. The outer year values are nearly identical to the data in that report.

CHAPTER 4: POLICY ISSUES FOR CENTRAL-STATION RENEWABLES DEVELOPMENT

This chapter addresses key policy issues for central-station renewable energy development, including the following: post-2010 goals, individual utility targets, the possible future role of RECs in the RPS, and challenges to meeting the goals. For each of these issues, the staff presents a summary of the issue, public comments from workshops, and next steps.

More Ambitious Renewables Portfolio Standard Goals Post-2010

The Energy Commission believes that ambitious longer-term RPS goals for the post-2010 period should be developed. This section discusses the rationale in support of more ambitious RPS goals post-2010, and possible effects of failing to pursue this recommendation.

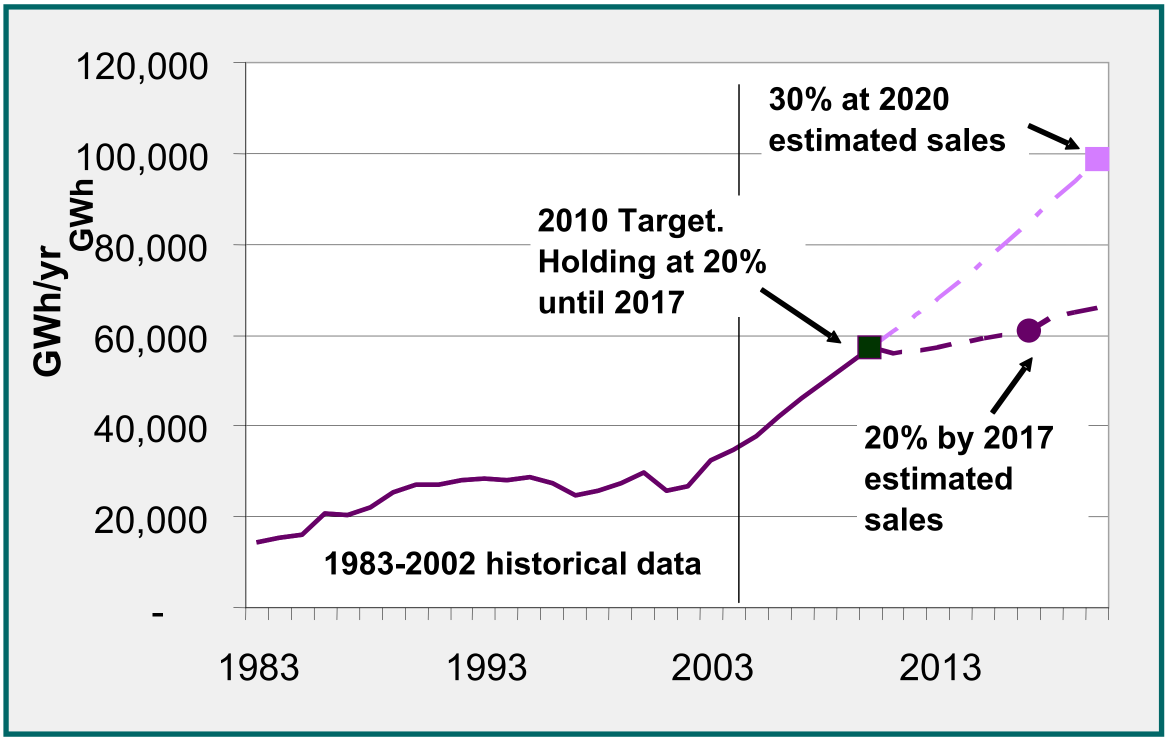
Baseload, intermittent, and peaking renewable energy generation costs have come down in recent decades, as reported in the Energy Commission's *Comparative Cost of California Central Station Electricity Generation Technologies,* while the *Renewable Resources Development Report* contains an estimate of future renewable energy costs.[1] Economies of scale and advances in technology have contributed to reductions in the cost of renewable energy generation. Policies encouraging long-term growth in PV based on competitive bidding can help maintain the momentum of these downward pressures on the cost of renewable generation.

As renewable energy potential is developed in California, the most readily harvested resources may become fully utilized, placing upward pressure on the cost of developing remaining technical potential. Future technological advances, such as low-speed wind turbines, may counter this trend and make previously marginal resources economically attractive. To spur continued innovation and development in the renewable energy sector, continued investment in such technological advances is needed.

Public sector funds can catalyze private sector investment if used to send clear signals regarding long-term demand for renewable energy. The accelerated RPS goal of 20 percent by 2010 provides such a signal for the next six years. However, bringing new technologies to commercial-scale applications often takes more than six years. Low-speed wind turbine technology, for example, is not expected to be widely available until 2011 or 2012.

As discussed above, this goal has been accelerated to 2010. After the IOUs meet the 20 percent goal in 2010, they must maintain the same percent for the next seven years. Thus, while the IOUs are expected to continue to add renewables beyond 2010, they are only doing so as their retail sales grow. As shown in Figure 6, this would mean a slow-down in the rate of growth of renewable energy generation after 2010.

Figure 6. Accelerated RPS Holding at 20 Percent through 2017



Source: Appendix A and *Renewable Resources Development Report,* 2003

If this path is followed, the rate of investment and innovation in renewable energy is also likely to slow, and the gains made in maintaining fuel diversity in the electricity sector may begin to erode. Setting post-2010 goals above 20 percent would help to avoid this outcome.

In the 2003 *Energy Report*, the Energy Commission recommended that the state adopt more ambitious RPS goals beyond mere maintenance of 20 percent between 2010 and 2017. However, the *Energy Report* did not state when or at what level the goal beyond 20 percent in 2010 should be set.

To reach 20 percent, current law states that retail sellers must add at least 1 percent per year until 20 percent is achieved by 2017, subject to certain cost constraints. With acceleration renewable energy development statewide to 20 percent by 2010 and addition of at least 1 percent per year through 2020, renewable energy would reach 30 percent of California's electricity retail sales by 2020.

With the IOUs apparently ahead of schedule in meeting the state's accelerated renewable energy goals, continuing this trend depends, among other things, on timely availability of transmission access. The greatest areas of concentrated renewable energy without existing transmission access are the wind resources in the Tehachapi Mountains and the geothermal fields near the Salton Sea. The white paper on transmission published concurrently with this paper discusses activities related to transmission for wind energy in the Tehachapi Mountains.

In addition to transmission constraints, some renewable resources, particularly geothermal, may require substantial lead time to complete environmental reviews and permitting. As a result, the estimated commercial operation date of many proposed geothermal projects is between 2011 and 2017, suggesting that post 2010-goals beyond 20 percent may be an important impetus for future geothermal development to meet California's electricity load.[2]

Public Comments on Post-2010 Goals

On May 4, 2004, the Energy Commission's *2004 Energy Report Update* Committee and Renewables Committee held a joint workshop regarding acceleration of renewable energy development in California. Regarding goals for the post-2010 period, the following questions were asked:

1. Should the state pursue additional renewable development beyond 20 percent of retail sales by 2010 through either mandates or incentive structures?
2. What benefits and barriers are associated with accelerated renewable development beyond 2010?
3. How and when should the state's accelerated goals be articulated, implemented, and evaluated?
4. How should these goals be adjusted as transmission availability, resource availability, and/or costs change?

A few stakeholders argued that longer term goals should be established earlier, rather than later.

- The Green Power Institute and the California Biomass Energy Alliance argued that it is important to lay an early foundation for the post-2010 period to avoid the "boom and bust" cycle that renewables experienced during the 1980s.

Most stakeholders argued that post-2010 goals should not be established at this time.

- The Independent Energy Producers argued that in order to convince the policy makers in the Legislature to increase renewable energy targets beyond currently recommended accelerated goals, an analysis of the first round of RPS procurements will be needed to provide estimated costs.

- SCE calls any post-2010 goals "premature."

- SDG&E argued that before extending the goal beyond 20 percent by 2010, the state needs to resolve transmission issues in California, establish a REC system, complete several RPS solicitations occur, and examine the prices for those renewable solicitations.

- Calpine suggests expediting the current RPS process now (e.g., hold the first solicitations soon) and then establishing broader goals in the future, possibly in 2008, if it appears that the 2010 goal can be met. In addition, Calpine has expressed concern that wind and geothermal projects may not come on-line in the amounts needed to achieve the 20 percent by 2010 goal. Further public comment regarding feasibility of achieving 20 percent by 2010 is discussed in the challenges and risks section of this chapter.

Since this workshop, substantial progress has been made in getting the RPS rules in place. PG&E and SDG&E recently released their first renewables solicitations under the RPS programs.

The staff agrees with the Green Power Institute and the California Biomass Energy Alliance that it is important to lay the foundation for post-2010 goals earlier, rather than later. A long-term plan will help the renewable industry plan and grow.

Next Steps for Post-2010 Renewables Portfolio Standard Goals

To maintain the momentum for accelerated renewable energy development, continue the investment in technology innovation, and drive costs down for renewables, the staff believes that there is a need for more ambitious RPS goals for the post-2010 period.

Individual Utility Targets

This section discusses whether an individual utility target should be set for any IOU that has reached 20 percent before 2010.

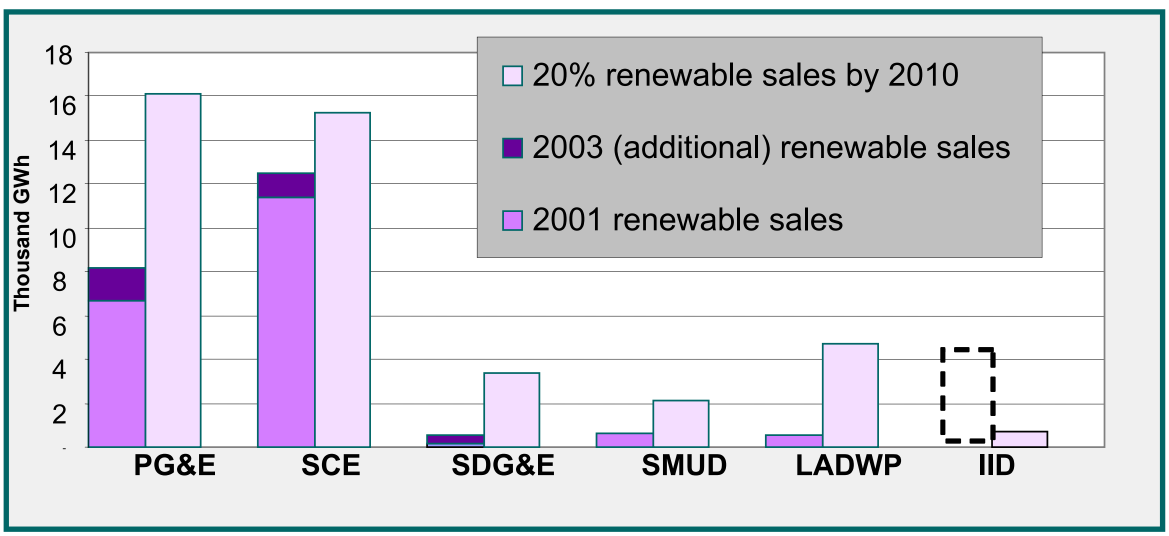
There is a mismatch between the location of resources and unmet renewables demand. To further public dialogue on this issue, this section compares existing renewable energy to gross technical potential for different regions of the state, highlights some of the possible effects of the mismatch for equity and cost allocation among IOUs, reports workshop comments on this topic, and discusses next steps.

Location of Resources versus Unmet Renewables Demand

There is a mismatch between the location of the gross in-state technical potential for renewable energy and the IOUs that are furthest from achieving the statewide goal of 20 percent renewable energy by 2010. The mismatch is particularly pronounced in the geographic area coinciding with the SDG&E service area. Complicating matters further, transmission lines bringing electricity into the SDG&E area are constrained. SCE and PG&E also face transmission constraints.

Each utility is starting from a different level of on-line and recently procured renewable resources (see Figure 7). The availability of cost-effective renewable resources also varies widely from utility to utility. There is no requirement that renewable resources be located within the service area of the utility that uses the energy to meet its RPS requirement, although importing renewables from other areas of California or other Western Electricity Coordinating Council (WECC) connected areas may require additional transmission capacity.

Figure 7. Comparison of 20 Percent by 2010 for Six Utilities in California



Source: Appendix A

While over 4,000 GWh of renewable energy was generated in the IID service territory in 2001, most of that energy is exported to other utilities for their renewable sales. The dotted box indicates the amount of energy generated in IID that is counted toward renewable sales elsewhere.

Table 6 shows the location of California's current renewable generation and the location of the technical potential but does not show which utility buys the energy from the facilities in the service territory.

Table 6. Renewable Generation and Gross Technical Potential by Location (Not Purchase Contract)[3,4]

Geographic Area	Estimated GWh in 2002 (actual performance varies)	Gross Technical Potential (GWh/year)
Northern California	22,703	45,226
Southern California (except SDG&E)	13,109	214,288
SDG&E	232	6,997
Total[5]	36,044	266,511

Source: *Renewable Resources Development Report*, 2003

As Table 6 indicates, over 80 percent of the renewable technical potential is located in the Southern California area (excluding San Diego), yet only 6 percent of this potential is currently being generated. On the other hand, only 17 percent of the total statewide renewable technical potential is located in Northern California. Of this potential, half has already been developed. The gross technical potential data reported in this chapter show gross technical potential only, without filters for economic, environmental, social, or cultural sensitivities.

Northern California Area

The Northern and upper Central portions of California are largely served by PG&E, PacifiCorp and several publicly owned electric utilities, including SMUD, Alameda Power and Telecom, and Redding Electric Utility. As a whole, there is approximately 45,000 GWh/year of renewable technical potential in this area. Of that amount, approximately 22,000 GWh of renewable energy could have been generated in 2002, approximately 50 percent of the total renewable technical potential. Table 7 provides a breakdown of 2002 generation and gross technical potential by renewable resource type in Northern California.

Table 7. Renewable Generation and Technical Potential in Northern California by Technology

Technology	Estimated Generation for 2002 (GWh)	Gross Technical Potential (GWh/year)
Biomass and Waste	4,103	11,201
Geothermal	14,513	15,681
Small Hydro	2,698	8,112
Solar	0	7,580
Wind	1,389	2,652
Total	22,703	45,226

Source: *Renewable Resources Development Report*, 2003

As Table 7 demonstrates, most of the potential and actual generation are represented by geothermal and biomass. The largest undeveloped potential in the Northern California area is solar (both thermal and PV), with approximately 7,500 GWh/year unused.

Southern California Area (Excluding San Diego County)

The Southern and lower Central portions of California are largely served by SCE and several other utilities, including LADWP, Anaheim Public Utilities, Riverside Public Utilities, and the IID. As a whole, renewable technical potential in this area is approximately 214,000 GWh/year. Of that, approximately 13,000 GWh/year of renewable energy could have been generated by existing facilities in 2002, only 6 percent of the total renewable technical potential.

Table 8 provides a breakdown of 2002 generation and technical potential by renewable resource type in the Southern California area, excluding San Diego County; however, transmission line constraints may pose a problem for bringing this potential to load. Much of the renewable energy potential is located in the Tehachapi Mountains and the Imperial geothermal fields. Transmission concerns in this area are discussed in more detail in the concurrent staff white paper on transmission.

Table 8. Renewable Generation and Technical Potential Located in Southern California (except San Diego) by Technology

Technology	Estimated Generation for 2002 (GWh)	Gross Technical Potential (GWh/year)
Biomass and Waste	1,854	5,885
Geothermal	7,050	21,653
Small Hydro	1,223	1,945
Solar	837	145,737
Wind	2,144	39,068
Total	13,109	214,288

Source: *Renewable Resources Development Report*, 2003

By far the largest source of renewable technical potential in the Southern California area (excluding San Diego) is solar, with most of the generation coming from the Solar Electric Generating Systems solar thermal (concentrating solar power) plants. In terms of generation, these plants generate approximately 800 GWh/year.

Biomass and small hydro typically generate between 1,000 GWh/year and 3,000 GWh/year, respectively, with some room for growth. Geothermal generates approximately 7,000 GWh/year, largely throughout the IID area. There is approximately 14,000 GWh/year of remaining technical potential that can be developed, again largely located in the IID area. Transmission out of IID is very limited, and this could prevent quick development of this geothermal potential.

Wind generates approximately 2,000 GWh/year, largely in the Tehachapi, San Gorgonio, and Palm Springs areas, with nearly 37,000 GWh/year of remaining technical potential that could be developed in these areas. However, transmission is not currently available to bring wind energy potential from the Tehachapi area to load. Transmission for the Tehachapi area is a topic under discussion in the CPUC transmission proceeding I.00-11-001.

San Diego County

San Diego County is served by SDG&E. Throughout the county, renewable technical potential is approximately 7,000 GWh/yr. On the generation side, in 2002 approximately 230 GWh could have been generated in the San Diego area, approximately 3 percent of the total renewable technical potential. Table 9 provides a breakdown of 2002 generation and gross technical potential by renewable resource type in San Diego County.

Table 9. Renewable Generation and Technical Potential Located in San Diego County

Technology	Estimated Generation for 2002 (GWh)	Gross Technical Potential (GWh/yr)
Biomass and Waste	179	672
Geothermal	0	0
Small Hydro	44	65
Solar	0	3,994
Wind	9	2,266
Total	232	6,997

Source: *Renewable Resources Development Report*, 2003

The two largest sources of renewable technical potential in San Diego County are solar and wind. In contrast, the existing renewable generation in this area comes from biomass and small hydroelectric power. Room for growth of these resources is limited by technical potential.

These data show that gross technical potential for renewable energy is concentrated in the Southern California area outside of San Diego County, and that SCE, which serves most of the load in this area, is very close to reaching the 20 percent by 2010 goal today. The next section discusses possible effects of this disparity between the location of renewable energy potential and unmet RPS retail sales requirements.

Possible Effects of Resource Location on Cost Distribution for the Renewables Portfolio Standard

The accelerated RPS allows each utility to meet its 20 percent by 2010 goal through the purchase of renewable energy from any location within the WECC electricity grid. Applying the same target to all IOUs is intended to treat utilities equitably, so the end result is that each utility will have the same percentage basis to procure renewable resources.

However, utilities have different levels of unmet RPS demand. SCE needs to add only a small percentage of renewables to reach 20 percent by 2010, while PG&E and SDG&E are further from the target, with SDG&E far behind the other two. In addition, San Diego County has limited undeveloped renewable energy potential.

To meet 20 percent by 2010, SDG&E is likely to need to import renewable energy from outside of San Diego County. Although SCE has large amounts of technical potential for solar and wind, much of this energy requires substantial investment in transmission infrastructure to bring it to load. If resources within SCE's service territory are to be developed for load in PG&E or SDG&E areas, SCE is likely to bear some of the infrastructure cost. It is not clear how responsibility for transmission planning and costs would be allocated in such a case. It is possible that even with SEPs, customers in one territory may end up subsidizing RPS compliance costs for another territory.

The policy recommended in the 2003 *Energy Report* for addressing this gap was to set different targets for utilities with greater gross technical potential. In practice, this would mean that the RPS targets for SDG&E and PG&E would remain unchanged, but the target for SCE would increase beyond 20 percent.

One possible approach is to set individual utility targets according to the wealth of available technical potential. An advantage of this approach is that it encourages additional renewable energy development by the utility that has the most flexibility in its least-cost-best fit criteria as to whether to bring the electricity in from outside the service area or meet it with in-area resources. A disadvantage of this approach is that it is difficult to measure the amount of gross technical potential that can be readily developed. As technologies and resource exploration continue over time, estimates of technical potential are revised.

Another approach is to set a new target for SCE to equal more closely the percentage increases that PG&E will need to meet 20 percent renewables by 2010. This approach reduces the difference between SCE's investment and PG&E and SDG&E's investments to meet the RPS.[6]

Public Comments Regarding Individual Utility Targets

At the May 4, 2004 joint committee workshop, stakeholders were asked to provide comments regarding the advisability of a number of options for pursuing individual utility targets in the state's RPS program, including no individual targets. Their responses are summarized in this section.

Workshop participants were asked to comment on the benefits and barriers of establishing differentiated targets for each of the IOUs, with the following questions:

1. Should RPS obligations differ by utility or retail seller, or should the obligations remain equal statewide as in current law? Please comment on the following alternatives:
    a. Each entity achieves an equal percentage of its retail sales from renewables (following the current RPS structure);
    b. Each entity achieves an equal percentage of the estimated renewable potential within its service area;
    c. Each entity's percentage varies, accounting for different renewable resource potential, deliverability, costs, and value among areas.
    d. How can the state maximize overall statewide benefits?
2. How should the varying amount of renewable energy available within each utility area be taken into account?
3. How should the transmission infrastructure, including utilization of existing transmission capability within and among utility areas, be taken into account?
4. How should differential costs of resource development in relation to electricity rates in each area be taken into account?
5. If differential targets make sense economically, should they be mandated or achieved through incentive structures? What mandates or incentive structures would you suggest?

A number of stakeholders commented verbally and in writing on the topic of individual utility targets.

- With respect to establishing specific RPS goals for each IOU based on potential renewable resources within the utility area, only Solargenix was in favor of this approach. Solargenix stated it supports "fair and equitable RPS goals that are unique and specific to each IOU" with respect to where the resource is located.

- Those opposed to varying RPS goals include the Green Power Institute, the California Biomass Energy Alliance, and Calpine. All three felt that the percentages should be equal, as this was the fairest way to implement the RPS.

- SDG&E indicated that it would need to participate in several RPS solicitations before it can comment on whether individual utility targets would be good for its ratepayers.

The staff agrees that specific IOU goals should be established based on the location of resources. To implement this approach, the staff believes that most retail sellers should have the same requirements, but IOUs with tremendous amounts of excess renewable potential should have higher targets.

Next Steps on Individual Utility Targets

The staff believes that a new target for SCE may be beneficial to the statewide objective of accelerating renewable energy development. SCE has shown leadership in this area in the past and its continued participation in renewable energy development is needed to maintain fuel diversity in the electricity sector. The level and methodology that should be used to determine a new SCE target requires further input from stakeholders. The staff suggests that an effort be made to reach consensus on this issue in the *2004 Energy Report Update*, to minimize uncertainty regarding SCE's participation in the state's efforts to accelerate renewable energy development. For PG&E and SDG&E, the staff believes that the 20 percent target is reasonable and should not be adjusted at this time.

Beyond the options discussed in this section, the RPS collaborative staff at the CPUC and the Energy Commission is looking into the possibility of allowing the use of unbundled RECs in future RPS solicitations.

Renewable Energy Certificates

A REC typically represents the environmental attributes of renewable energy as a separate commodity from the electricity. For this discussion, the term REC used in its broadest definition means the "renewable attributes" of a given unit of renewable-based generation, as distinct from the underlying electrical energy. Other terms often used interchangeably with RECs include: "green tickets," "green tags," and "renewable credits." A REC represents the renewable attributes associated with one megawatt hour (MWh) of renewable-based electricity that has been generated.

As noted in the introduction, a REC may be "bundled" with the underlying electricity or sold separately ("unbundled"). If a REC is unbundled from its associated energy, it is often termed a "Tradeable Renewable Energy Certificate" (TRC or TREC). In the WECC, RECs (both "bundled" and "unbundled") will be tracked. California plans to rely on this as an accounting tool for IOU compliance with the RPS.[7] The Energy Commission is developing an automated accounting system, the Western Renewable Energy Generation Information System (WREGIS), which will use RECs to track renewable generation and procurement. The tracking system is discussed in more detail below.

However, California's RPS program does not currently allow the IOUs to procure unbundled RECs to meet RPS obligations; RECs purchased without the associated electricity do not qualify. Instead, RECs procured for RPS compliance must remain bundled with the associated renewable electricity.

The enabling legislation for the RPS is structured around the IOUs entering long-term contracts for electricity deliveries from renewable generators. Specifically, the legislation envisions contracts for baseload, peaking, and intermittent renewable generation, which would not be necessary if the RPS was designed to allow compliance through the procurement of unbundled RECs. For example, SB 1078 requires the IOUs to develop renewable procurement plans in which they describe their RPS solicitations as follows:

> Consistent with the goal of procuring the least-cost-best-fit eligible renewable energy resources, the renewable energy procurement plan submitted by an electrical corporation shall include, but is not limited to, all of the following:
>
> (A) An assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of renewable generation resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.
>
> (B) Provisions for employing available compliance flexibility mechanisms established by the [public utilities] commission.
>
> (C) A bid solicitation setting forth the need for renewable generation of each deliverability characteristic, required on-line dates, and locational preferences, if any.
>
> In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years in duration, unless the [public utilities] commission approves of a contract of shorter duration.

Further, for out-of-state resources, Senate Bill 67 (SB 67, Chapter 731, Statutes of 2003, Bowen) and Senate Bill 183 (SB 183, Chapter 666, Statutes of 2003, Sher) add the following requirements to the Public Utilities Code regarding electricity deliveries from RPS eligible renewable resources:

> 399.16. The [energy] commission may consider an electric generating facility that is located outside the state to be an eligible renewable energy resource if it meets the criteria described in Section 399.12 and all of the following requirements:
>
> (a) It is located so that it is, or will be, connected to the Western Electricity Coordinating Council (WECC) transmission system.
>
> (b) It is developed with guaranteed contracts to sell its generation, and demonstrates delivery of energy, to a retail seller or the Independent System Operator.

SB 1078 tasked the CPUC, in collaboration with the Energy Commission, to develop RPS implementation rules by June 30, 2003, six months after the law became effective. Given the complexity of the law, the active participation of a wide group of stakeholders representing a breadth of positions, and the limited time, the CPUC made efforts to limit the scope of the analysis where possible. The CPUC's June 2003 decision stated: [8]

> We understand that a number of parties believe a REC trading system to be highly desirable, but the creation of such a trading system is far beyond the scope of what we must accomplish by the statutory deadline of June 30.

Although the legislation does not directly state that the unbundled RECs cannot be used to comply with the RPS, the CPUC has done so, at least in the interim, through regulatory decision:[9]

> Some parties advocated that the [Public Utilities] Commission should ultimately adopt a REC trading system, where RECs could be bought and sold separately (or "unbundled") from their associated underlying energy. (See, e.g., Ridgewood, Ex. RPS-8, p. 3.) Under this scenario, a utility could meet its RPS obligation by purchasing RECs from a renewable generator without purchasing the corresponding energy from that same generator, and a generator would be free to sell its RECs to someone other than the buyer of its energy.
>
> Administrative Law Judge Allen ruled that a REC trading system would not be considered in this phase of this proceeding, and we confirm that ruling here.

Further, the CPUC decision states,

> While we will leave open the possibility that a REC trading system may be implemented in the future, we note that such a system raises a number of significant issues that would need to be addressed.

The CPUC cites the following issues that should be addressed in considering whether IOUs may use tradable RECs in the future for RPS compliance:

> Before we consider adoption of a REC trading system, we will need a clear showing that a REC trading system would be consistent with the specific goals of SB 1078 [e.g. public health, economic development, job creation, environmental, and other benefits anticipated by the statute], would not create or exacerbate environmental justice problems, and would not dilute the environmental benefits provided by renewable generation. Our recent experience in California with electricity markets has also sensitized us to issues of market manipulation, and we would want to be sure that a REC trading system could not be gamed to the detriment of the residents of California.

The next section explores the current status of the REC market and other issues in considering whether California's RPS should be modified in the future to allow unbundled RECs to count towards meeting RPS targets.

Trading Unbundled Renewable Energy Certificates

Currently, there are regulated and voluntary markets for unbundled RECs, the growth trends of which are discussed below. This section is intended to provide an overview of how unbundled RECs are traded.

A hypothetical example may help to demonstrate how RECs are traded. In this example, the market includes a renewable generator, a wholesaler, a utility, and a large industrial consumer. The renewable generator produces 100 MWh of renewable electricity, and offers two commodities to the market: 100 MWh of electricity, and RECs representing the environmental attributes from 100 MWh of renewable electricity. The renewable generator in this example sells the electricity and RECs to a wholesaler. The wholesaler then makes the following market transactions:

1. Sells 60 MWh of the electricity from the renewable generator and the associated 60 MWh of RECs to the utility (this bundled sale would meet California's RPS);
2. Sells 40 MWh of RECs to the industrial customer who is interested in supporting renewable energy to improve its public image or financially support renewable development (the customer buys its electricity from the local utility, and the transaction does not count towards California's RPS); and
3. Sells 40 MWh of unbundled electricity to the spot market or a utility, with no market claim that the electricity is renewable.

All of the above transaction would be consistent with existing law and would not result in double counting. "Double counting" refers to the situation in which more than one party bases a market claim of renewable energy on the same unit of electricity production. An example of double counting would be the following: if one party meets an RPS procurement target by purchasing all the electricity generation and RECs from a renewable facility in a given year, and another party bases a different market claim on a portion of the electricity generated from that facility in the same year.

Another market opportunity is for parties to purchase unbundled RECs from one party, and a corresponding amount of electricity from another party coupled together in one product. This product may be described as "bundled green power." Although this practice currently would not qualify for California's RPS, it is allowed, for example, under Oregon's regulatory requirements for utilities. Also, this is a typical practice for ESPs serving "green" power in California.[10]

It is important to recognize that a voluntary, unregulated market is currently active in California and throughout the nation (as discussed further in the subsection titled, "Retail Use of Unbundled Renewable Energy Certificates").

Some consumers and large organizations choose to “green up” their electricity consumption by purchasing unbundled RECs directly from retail marketers as described in the second transaction in the scenario above. Since the state does not regulate or specifically track this market, we do not have a measurement of its size.

Unbundled RECs allow the renewable energy attribute to be separated in time and geographic location from the electricity produced, providing more flexibility for generators, retail providers, and consumers in the markets where allowed. RPS requirements in many other states require only an annual compliance demonstration. In such programs, demonstration of delivery or a minute-by-minute match of renewable generation and consumption is unnecessary. States with RPS policies that allow unbundled RECs for RPS compliance purposes include Arizona, Connecticut, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, Rhode Island, Texas, and Wisconsin.

Renewable Energy Certificate Tracking Systems

Although unbundled REC trading is currently not allowed for IOU compliance with California’s RPS, the CPUC and Energy Commission are implementing a REC accounting system, consistent with the law. SB 1078 requires the Energy Commission to:

> Design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state. [11]

The tracking and verification of renewable energy can be achieved through two alternative approaches: (1) the review of contract paths, or (2) a REC-based electronic tracking system. A REC-based electronic system may be designed so that RECs are created when renewable electricity is generated, and RECs are held or transferred between parties in a process similar to transferring funds between bank accounts. The Energy Commission is collaborating with the Western Governors’ Association to develop an electronic, REC-based tracking system to meet the long-term accounting needs for the RPS.[12]

In its June 2003 decision, the CPUC also supported developing a REC-based accounting system. The CPUC recognized that the advantages of such a system include the flexibility to track unbundled RECs if their use is allowed for California’s RPS in the future. The decision states:

> Nevertheless, a REC-based system has a number of advantages. First, if the [Public Utilities] Commission were to ultimately adopt REC trading, the

process of doing so would be simplified if a REC accounting system was already in place, as opposed to dismantling some other accounting system and then restarting from scratch [note omitted]. Second, REC-based systems are relatively simple and efficient, particularly when compared to the alternative contract path system [note omitted]. Finally, a REC-based system appears to be particularly well suited to preventing double counting of attributes, as required by § 399.13(b) [note omitted].

The National Association of Attorneys General has issued guidelines for the appropriate marketing of the environmental benefits of electricity. One of the goals of the guidelines is to ensure against double counting for consumer protection.[13]

Today, contracts with renewable generators typically specify if the transaction includes the transfer of RECs from the seller to the buyer. REC-based accounting systems can efficiently track such transactions and serve various policies and programs on a local, state, regional, or federal level, including the following actions:[14]

- Verify compliance with renewable portfolio standards;
- Verify utility green pricing programs (these are programs in which utilities offer consumers the option to specifically purchase renewable energy at an added cost);
- Track and verify voluntary retail markets for renewable energy outside of utility green pricing or other regulatory programs (e.g. individual consumers, corporations, and other institutions interested in supporting "green" power through their own initiative, separate from any mandate or utility program);
- Verify the quantity of renewable energy generated in the Western Interconnection;
- Track renewable transactions at the wholesale level;
- Accommodate commercial trading of RECs; and
- Accommodate renewable energy policies other than those listed above.

Electronic REC-based tracking systems are now in place in New England, Texas, and Wisconsin, and are under development in the PJM region (i.e., Illinois, Ohio, and East Coast states from Pennsylvania south to Virginia), Ontario, Canada and the western United States.[15] Virtually all of the renewable facilities located in New England and Texas now record REC generation automatically through their tracking systems. In Texas, unbundled RECs are used to meet the RPS obligations for that state. In the New England region, the New England Power Pool Generation Information System tracks and verifies RECs used to meet the renewable claim obligations of New England states that are participating in the program.[16]

It is useful to distinguish REC *accounting* or *tracking* systems from REC *trading* systems. REC tracking systems account for the transfer of ownership between parties, but monetary exchanges between parties buying and selling RECs is external to the tracking system. REC trading systems include information regarding monetary exchanges. The REC tracking system envisioned by the Energy Commission to meet SB 1078 requirements is not intended to be a trading system, and information on prices will not be recorded.

Western Renewable Energy Generation Information System

Recognizing the value of regional, REC-based tracking systems, California is actively participating in the development of WREGIS. The tracking system will encompass the geographic boundary of the WECC, including: 14 western states, western Canadian provinces and the northern portion of Baja California, Mexico. The tracking system is expected to be operational by the end of 2005. The Western Governors' Association, the Western Regional Air Partnership, and the Energy Commission sponsor the project.

WREGIS will be a voluntary accounting system that tracks renewable energy generation, issues RECs, and accounts for REC transactions. WREGIS will issue a unique REC for each MWh of renewable generation that identifies a variety of data, including the generation date (month, year), the fuel used, and the facility from which the REC originated. The tracked information will also indicate whether the REC is eligible for compliance with various states' policies.

WREGIS will function like a bank, such that RECs will be "deposited" in a generator's account when data are available to verify the amount of renewable electricity generated. RECs may be "withdrawn" from the generator's account and transferred to another account holder (such as a utility or other retail seller) when both parties agree. Once a REC is used to demonstrate compliance with a retail claim such as the RPS, it will be "retired" and no longer available for market use.

The process for developing WREGIS is ongoing and strongly supports stakeholder input. It reflects input from over 216 individuals representing utilities, market participants, tribal organizations, project developers and other stakeholders.[17] The Western Renewable Energy Generation Information System sponsors continue to invite public participation and post ongoing work on the Western Renewable Energy Generation Information System website for review and comment.[18]

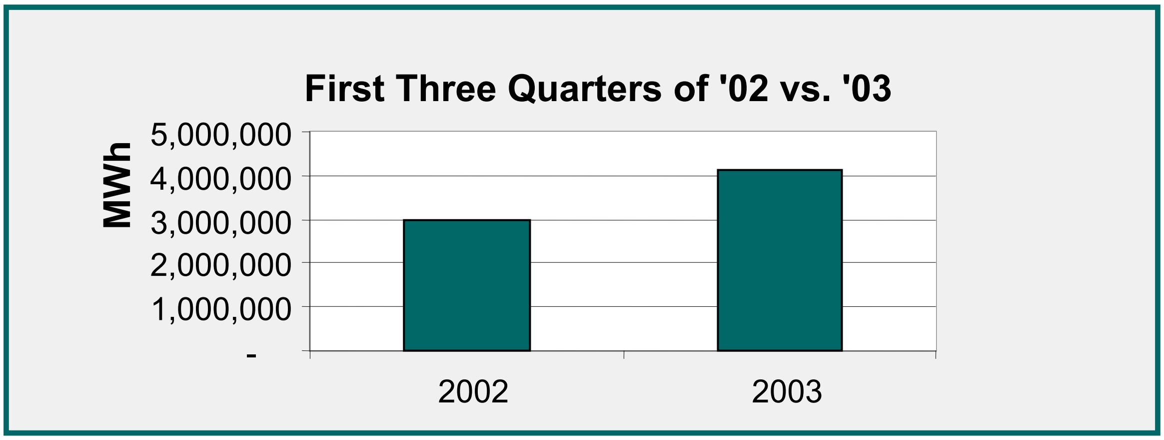
WREGIS can be used to support tracking of bundled and unbundled RECs. Tracking bundled RECs requires an additional level of verification to ensure electricity delivery that would not be needed if California allowed unbundled RECs.

Commercial Wholesale Market Trends

Unbundled RECs are becoming a common way of meeting RPS mandates in other states, especially among competitive energy service providers, but also by rate-regulated electric utilities. Within recent years, the wholesale electricity market has largely converted to using contracts that specify RECs as a specific product from a renewable generator.

One possible approach to assess the size of the wholesale RECs market is to look at the volumes of MWh in the major tracking systems operating today. Figure 8 indicates that New England's RECs market saw a 37 percent increase in volume in the first three quarters of 2003 versus the same period in 2002, over one million MWh of RECs.[19]

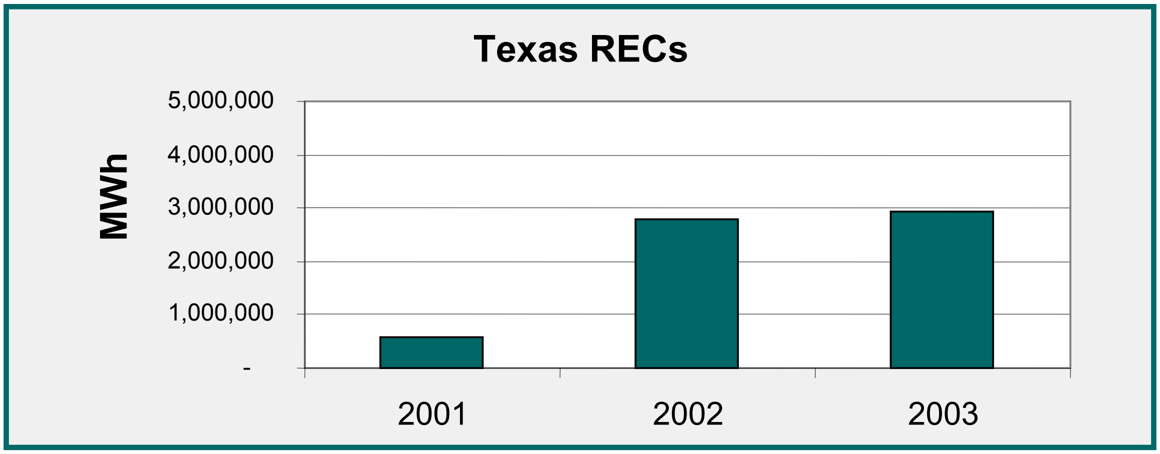
Figure 8. Growth in New England Power Pool RECs



Source: New England Power Pool Generation Information System

Texas, the first tracking system to begin operating in the US, saw growth of under 10 percent, consistent with the fact that the capacity installed in Texas to date substantially exceeds regulatory requirements and much of that capacity is congestion-constrained at this time (See Figure 9).[20]

Figure 9. Growth in Texas Renewable Energy Certificates



Source: Electric Reliability Council of Texas, "Renewable Energy Credit Program Information: Quarter/Annual Renewable Energy Generation in Texas by Technology Type," [http://www.texasrenewables.com].

The wholesale REC market is now national in scope with a growing set of market participants. The number of wholesale REC brokers has increased over the last year and RECs representing all major renewable resources are available in the market.[21] Unbundled REC prices range from $1.50/MWh for 2003 vintage new wind, to the premium paid for new solar RECs, which can fetch a price 100 times higher at $150/MWh.[22] The volume of unbundled RECs offered for sale in the voluntary market in a given month, available through a single broker, may be in the hundreds of thousands of MWhs.[23]

Green-e is a non-profit organization that certifies renewable energy products that meet specific environmental and other standards. Nineteen companies are currently selling unbundled REC products that are certified by Green-e. In another measure of the growth of the market in the past year, Green-e's preliminary evaluation of the combined wholesale and retail unbundled RECs certified in 2003 was 1.8 thousand GWh, twelve times larger than in 2002. Green-e anticipates that the 2004 market will at least double the 2003 market. For comparison, the annual procurement target of the three IOUs combined is 22.6 thousand GWh.[24]

The vast majority of unbundled RECs are sold at the wholesale level. Wholesalers typically re-bundle RECs with generic power sources to supply bundled green power to retail customers. This process avoids the need to contract for bundled renewable energy out of a specified plant in a manner that matches the customers' load curve.

Retail Use of Unbundled Renewable Energy Certificates

The sale of unbundled RECs directly to retail customers, without deliveries of electricity, is also growing. The market is dominated by commercial customers interested in having a product designed to meet their specific interests. Commercial customers value the public perception of promoting renewables and their purchase of unbundled RECs is an increasingly popular means of doing so.

The market for unbundled RECs offers attractive choices for many consumers. The market provides a choice for consumers that otherwise do not have access to purchase a renewable electricity product. For example, many consumers live in the distribution area of a utility that does not offer renewable energy products. In the past, California consumers had the opportunity to purchase renewable energy directly from ESPs rather than purchasing electricity from their utility, but that option is now closed to new customers.[25] Also, if a large consumer has operations scattered throughout the distribution territories of multiple utilities, the consumer may prefer to procure unbundled RECs from one party rather than negotiate deals with several different utilities or ESPs, even if electricity providers offer a renewable option.

A marketer or trader may offer unbundled RECs from a variety of renewable facilities at quantities, vintages, and resource types that match the consumers' interests. Other consumers are particularly interested in procuring unbundled RECs to support the development of new facilities, or as a means of offsetting the potential impacts associated with their production of greenhouse gas emissions.

Unbundled RECs also offer an alternative to large commercial customers who have the means to procure electricity directly from the market. The consumer may prefer to have the flexibility of entering into purchase agreements with a REC marketer or trader for one or two years, rather than entering into a longer term commitment to purchase bundled electricity and RECs.

Although the residential sector makes up a smaller portion of the unbundled RECs retail market than the commercial sector, marketers offering retail unbundled RECs to individual consumers are on the rise. Eleven retailers offer Green-e certified unbundled RECs and several other retailers offer unbundled RECs directly to customers nationwide.

Consumers in California currently purchase unbundled RECs through the voluntary, unregulated market. The data on such transactions are generally anecdotal and made available through press releases for large-scale purchasers. Examples of organizations in California that have purchased unbundled RECs include: the National Resources Defense Council office in Santa Monica, Wild Goose Restaurant in Tahoe, and Trout Unlimited California.[26]

Potential Advantages and Disadvantages

California policy makers are exploring whether the RPS should be modified to allow unbundled RECs to qualify towards the IOUs' annual procurement targets. More broadly, policy makers could allow other retail sellers, or all retail sellers, to meet their RPS obligations with unbundled RECs. Bills have already been introduced in the Legislature to allow REC trading. Determining whether unbundled RECs should qualify for the RPS hinges on weighing the advantages and disadvantages of such a policy to advance California's goals.

A possible disadvantage raised by the CPUC that needs to be further explored is whether allowing unbundled RECs would create environmental justice issues. For example, if an IOU procured unbundled RECs from a new wind facility outside its service territory and a matching amount of fossil fuel-based electricity generated locally to serve its load, then the renewable energy would not result in air quality benefits in the local area. Another consideration is whether other benefits of renewable energy, such as economic development or electricity price stability, would be reduced or would accrue in the place of generation rather than in the purchasing utility's service area.

The CPUC also raised a concern that allowing unbundled RECs to meet the RPS would invite market manipulation, or double counting, which might otherwise be avoided. Safeguards are needed to ensure that an RPS contract for bundled renewable electricity is not stripped of its electricity. For example, a second contract for an instantaneous reverse delivery of the electricity would result in a net procurement of unbundled RECs, rather than bundled renewable electricity.

A potential advantage worth exploring is whether the use of unbundled RECs could reduce the need for added transmission lines, or relieve transmission congestion. This depends on the location of the renewable resource and available transmission lines to serve unmet RPS demand. The following examples illustrate the way these factors interact:

- If concentrated cost-effective renewables are located in remote areas, new or upgraded transmission lines may still be necessary, even if unbundled RECs are allowed.

- Some parts of the state have a higher potential for renewable development than others. If each retail seller must deliver bundled renewable energy into its service territory, this may not foster efficient transmission development.

- Where transmission of concentrated renewable energy development to utilities with unmet RPS demand is impeded by transmission congestion, unbundled RECs could be used to meet RPS demand while circumventing the congested transmission area.

The use of unbundled RECs to meet the RPS could be implemented in a number of ways:

- IOUs could be allowed to trade unbundled RECs among themselves, but not with others. IOUs could be required to use bundled RECs for other transactions.
- IOUs could be allowed to meet a portion of their procurement target with unbundled RECs.
- IOUs could be allowed to meet their entire procurement target with unbundled RECs.
- Bundled renewable electricity bids could be eligible for SEPs, but bids using unbundled RECs would be excluded.
- The use of unbundled RECs for RPS and/or SEP eligibility could be restricted to renewable generators located in the WECC.
- The public could be informed about the tradeoffs between bundled and unbundled RECs and given the option to opt in to an “RPS by unbundled REC” product. The electricity demand from customers opting into the unbundled REC product would place an upper limit on the proportion of the IOUs’ annual procurement target that could be met with unbundled RECs.

These variations in implementation of the RPS could affect whether inclusion of unbundled RECs in the RPS is beneficial or disadvantageous to the state. The implementation options given above for IOUs could also apply to publicly owned electric utilities, with the exception that publicly owned electric utilities’ RPS solicitations do not qualify for SEPs.

Unbundled RECs may provide a reasonable means for ESPs and CCAs to comply with the RPS. Unlike the IOUs, ESPs and CCAs cannot be assured a guaranteed revenue stream for a long-term power purchase agreement. These organizations are typically relatively small and may not have the credit backing to support investments in power purchase agreements. Consequently, ESPs and CCAs enter short-term electricity contracts with relatively small financial commitments and flexibility to respond to market changes. The ESPs and CCAs short-term procurement practices suggest that unbundled RECs may be an appropriate compliance option for this market sector.

Public Comments on Unbundled Renewable Energy Certificates

The Energy Commission’s IEPR Committee held a workshop on May 4, 2004 to explore the use of unbundled RECs, especially as they relate to accelerating RPS goals. The comments received are summarized at the end of this section, and further public input will likely be needed for the *2005 Energy Report*.

Below are the questions raised at the *2004 Energy Report Update* workshop. Where questions refer to “a REC trading system,” the intent was to explore the implications of allowing unbundled RECs to qualify for the RPS, although the terminology was different than what is used in this white paper.

1. What information is available or should be developed to provide a clear showing of the type requested by the CPUC? What are the necessary features of a REC trading system?
2. How could unbundled RECs be used with in-state delivery requirements under the RPS? What benefits would their use provide in this context? What costs?
3. If a REC trading system is adopted, how should, if at all, a MPR be established for an unbundled REC transaction that does not include the associated electricity?
4. If a REC trading system is adopted for California's RPS, should SEPs apply to unbundled REC-only transactions, if at all?
5. How is the ownership of RECs affected when public goods charge funds support the associated renewable energy in the form of SEPs or other state or federal incentives?
6. How is the ownership of RECs affected where general ratepayer investment in renewable energy is supplemented by private funding support in the form of green pricing premiums or other funding?

All of the stakeholders from the May 4, 2004 workshop tentatively supported the use of RECs, with some cautionary notes:

- The Independent Energy Producers favor a REC market, as long as it is clear that the REC ownership remains with the generator, unless explicitly transferred to the utility.

- The Green Power Institute and the California Biomass Energy Alliance argue that smaller utilities, ESPs, and CCAs do not have the ability to enter into long-term contracts with renewable providers. For this segment of the market, they argue, separable REC trading may offer the best opportunity for providers to efficiently achieve RPS compliance.

- The Clean Power Income Fund stated that REC trading would allow California to meet its RPS goals efficiently and with the least cost to ratepayers.

- Calpine stated that ESPs and CCAs should be allowed to use RECs to satisfy their RPS requirements. Also, Calpine stated that RECs would benefit California, provided they are coupled with in-state delivery and priced in a manner to insulate ratepayers from fossil fuel prices.

- Solargenix argued that RECs should be allowed for RPS compliance and that those RECs should be valued differently based on the type of generation (i.e. wind is "as-available" and solar thermal is "on-peak," thus the solar would be worth more).

- PPM Energy indicated that RECs provide flexibility and help with least-cost-best-fit. Further, RECs will help publicly owned electric utilities to comply with the RPS**.**

The staff concurs with the stakeholders that unbundled RECs could solve many of the problems associated with the RPS. At this time, however, there are still too many unanswered questions for the staff to endorse the use of unbundled RECs for RPS compliance.

Next Steps on Unbundling Renewable Energy Certificates

The use of RECs will be explored further in the *2005 Energy Report*. Staff recommends that the Energy Commission evaluate and weigh the advantages and disadvantages of allowing unbundled RECs to be eligible for the RPS, including the following:

- Evaluate whether unbundled RECs create environmental justice issues.
- Evaluate whether unbundled RECs increase the risk of market manipulation, and identify actions the state can take to foster market credibility.
- Identify opportunities to increase the efficiency of transmission upgrades or reduce the need for transmission expansion with the use of unbundled RECs.
- Consider whether unbundled RECs are a prudent option for ESPs and CCAs.
- Identify whether publicly owned electric utility programs allow unbundled RECs, and consider the advantages and disadvantages of a policy which allows a subset of utilities to meet RPS targets with unbundled RECs. See Chapter 3 for additional information on this topic.

Challenges and Risks

Recent procurements indicate that the IOUs are on a trajectory to meet the 20 percent by 2010 target. PG&E, SCE, and SDG&E all increased their renewable sales by over two percentage points between 2001 and 2003, without payment of SEP funds to renewable projects. It is likely that additional renewable projects procured during the 2003 Interim Procurement ordered by the CPUC will continue to come on-line in 2004, boosting these percentages higher.

Many factors could prevent the state from reaching 20 percent renewable energy by 2010. One potential barrier is access to available and cost-effective transmission in locations where the renewable resources are located. Other risks include adequacy of public goods charge funds for SEPs and the ability to construct certain projects before 2010, especially those with difficult permitting issues.

The following section provides an overview of challenges and risks related to reaching 20 percent renewable energy by 2010.

Transmission

The timely availability of transmission access for renewable generators — particularly wind, solar central station, and geothermal — presents a significant risk to the accelerated development of renewable resources to meet the future RPS targets.

The acceleration of renewable development under the RPS has highlighted the role of transmission in renewable energy resource development. The transmission issues for renewable resources tend to focus on transmission interconnection of large amounts of renewable resources being developed in concentrated areas. Transmission issues for renewable energy facilities are not nearly as challenging for transmission planning when the facilities are dispersed as single units or as small clusters of units scattered throughout the electricity grid. However, current transmission planning conducted by the CA ISO and IOUs has not adequately captured or assessed transmission needs for renewable resources.

In areas with large amounts of highly concentrated renewables, the transmission challenges are compounded. Two factors contributing to these challenges are 1) multiple owners/developers competing to develop their projects over various timeframes; and, 2) multiple owners/developers competing for limited or not-yet-existing transmission access. It is difficult to coordinate the number, variety, and wide-ranging on-line dates of large numbers of relatively small-scale renewable energy projects, while planning for overall transmission system needs.

Transmission projects usually have long lead times and require assurance of economic viability. In contrast, renewable energy development for the RPS is expected to have relatively short lead times and to occur in relatively small increments. Furthermore, renewable energy projects are subject to the establishment of a buyer and seller relationship to assure payment of the transmission costs.

The current transmission interconnection model for new generation is based on single location power plant development. As a result, this model does not fit the characteristics of renewable energy development. The risk of planning transmission on a plant-by-plant basis using the current system is the development of a sub-optimal system. In contrast, the risk of planning for long-term renewable energy development provides a more optimal transmission system, but assumes that these multiple developers will bring their plants into operation on schedule. If they do not complete construction as anticipated, the projects will not be able to repay the construction costs of the transmission lines.

Options to plan for such contingencies are uncertain at this time. The completion of the first few RPS solicitations coupled with the developing revisions to the CPUC transmission planning process to address transmission for RPS should provide insight into solutions for the renewables-related transmission dilemmas.

One of the long lead-time items for transmission line development is right-of-way acquisition and permitting. The use of pre-approved transmission corridors effectively zoned for the development of future transmission lines could shorten the lead time required for future development.

Some transmission issues may be partially mitigated through the use of unbundled RECs for the RPS; however, the relationship between RECs and transmission should not be oversimplified.

If unbundled RECs are allowed, RPS bids could match unbundled RECs with non-renewable electricity. It is possible that electricity from a non-renewable generator could be moved at the time of generation to the buyer without encountering transmission congestion. This would provide an alternative for utilities that would otherwise need to finance significant transmission upgrades to overcome congestion and allow them to bring renewable energy to load. The electricity from the renewable generator, stripped of its “renewable” label, would be delivered from the generator to a different buyer over available transmission lines.

Similarly, where there is little load growth or utilities do not have the authority or financial structure to utilize long-term renewable energy contracts, unbundled RECs can add an alternative mechanism for “greening” non-renewable energy from existing contracts or short-term purchases.

Nonetheless, building transmission to access renewables, especially remote renewables like those in Tehachapi and the Salton Sea, will be necessary to take advantage of some of the best and most cost-effective renewables. RECs may be able to help transfers of renewable attributes between utilities but cannot, however, obviate the need for transmission infrastructure to access renewable energy and meet RPS targets.

Public comments and next steps for addressing transmission issues are discussed in the concurrently released staff white paper on transmission.

Public Comments Regarding Barriers to Reaching 20 Percent by 2010

Several stakeholders at the May 4, 2004 workshop commented verbally and in writing on barriers that may prevent California from meeting the 2010 RPS target date.

- The Green Power Institute and the California Biomass Energy Alliance caution that SB 1078 SEP funding may not be sufficient to support the 2017 target, let alone the accelerated target for 2010.

- Numerous parties, including SDG&E and SMUD, warned that transmission will be a barrier to achieving the RPS.

- Calpine states that to meet the 2010 RPS, 3,000 MW of baseload renewables or 10,000 MW of wind, or some combination, will need to come on-line. Given the time required to permit, develop, finance, and construct these projects, the contracts will need to be in place this year or next. Calpine does not believe this will happen. Furthermore, Calpine believes that the "progress to date" has not been successful, and suggests that 2010 RPS date will not be met. Finally, Calpine indicates that the considerable length of time it takes to permit a project in California makes meeting the 2010 target difficult.

The staff agrees it is possible that there will not be enough SEP funds, but notes that it is also possible that the competitive RPS solicitation process will result in prices that do not exhaust the available public goods charge funds. It is also important to note that if SEPs are inadequate to reach the annual procurement target for a given year, utilities will purchase only the lower cost renewable bids (i.e., below the MPR) available that year.

The staff is also concerned about the availability of transmission. As discussed above, transmission is the focus of a separate white paper, though it is recognized here as a barrier for renewable development.

The staff notes that renewables have been procured by the IOUs in large quantities since 2001. This trend in renewables procurement in recent years is greater than the minimum amount required to meet 20 percent by 2010.

Regarding difficult permitting issues, the staff notes that re-powered or new wind facilities in the Altamont area will not receive permits until planning officials are confident that steps have been taken to prevent avian mortality. Bat deaths from wind turbines are becoming an environmental concern as well.[27]

The staff agrees that permitting, developing and financing will need to be in place soon to meet 20 percent renewables by 2010.

Next Steps on Barriers to 20 Percent by 2010

Currently, there is too much uncertainty regarding MPRs, winning bid prices, maintenance of baseline, and interest rates to determine whether public goods charge funds will be adequate to meet the acceleration of the RPS. At the conclusion of the first solicitation under the RPS later this year, the staff plans to re-evaluate the adequacy of public goods charge funds for this purpose. Further discussion of this issue is planned for the 2005 *Energy Report*.

As noted in the section on post-2010 goals, the staff believes that there is a need for longer-term goals to provide certainty and stability for the continued healthy growth of the industry.

Notes

[1] California Energy Commission, June 2003, *Comparative Cost of Central Station Electricity Generation Technologies*, 100-03-001F, [http://www.energy.ca.gov/reports/reports_100.html], accessed July 17, 2004. An estimate of the levelized cost of energy for new central-station renewable energy plants installed in 2005, 2008, 2010, and 2017 (with and without extension of the federal production tax credit) is reported in the California Energy Commission, November 2003, *Renewable Resources Development Report*, 500-03-080F, [http://www.energy.ca.gov/renewables/02-REN-1038/documents/index.html], accessed July 17, 2004. See pages 35-46 and Appendix D.

[2] For example, the accelerated RPS supply scenario reported in the *Renewable Resources Development Report* (p. 97), shows an on-line date between 2011 and 2017 for 44 percent (2,550 GWh/yr) of geothermal developed to meet a statewide target of 20 percent by 2010, maintaining out to 2017.

[3] California Energy Commission, November 2003, *Renewable Resources Development Report*, 500-03-080F, [http://www.energy.ca.gov/renewables/02-REN-1038/documents/index.html], accessed July 17, 2004, see Appendix C.

[4] The gross technical potential estimated in this paper (266,511 GWh) is slightly higher than the gross technical potential estimated in the *Renewable Resources Development Report* (262,546 GWh). The only difference is in the way small hydro is counted. In the *Renewable Resources Development Report*, “Technical Potential” and “Annual Energy Production (GWh)” for small hydro were assumed to be total technical potential. However, it now appears that those were only the incremental technical potential. Therefore, the existing small hydro values were added to the *Renewable Resources Development Report* incremental to derive a new gross technical potential. However, neither the *Renewable Resources Development Report* nor the new estimate for small hydro accurately indicates how much remaining technical potential is available where the sum of the existing and remaining remains below the 30 MW required to be considered eligible for the RPS. For the RPS, the California Energy Commission interprets the 30 MW size limit to apply to the total hydro project. Consequently, the facility must not exceed 30 MW, including any incremental increases to the efficiency or size of the facility. For example, a 5 MW incremental addition to a 50 MW facility would not qualify for the RPS because the facility exceeds the 30 MW size limit. For further information on small hydro eligibility in the RPS, see California Energy Commission, May 2004, *Renewables Portfolio Standard Eligibility Guidebook*,

500-04-002F, [http://www.energy.ca.gov/portfolio/documents/index.html], accessed July 28, 2004.

[5] The “Estimated GWh 2002” value is a hypothetical number of what could have been generated had all the plants operated at the assumed capacity factors throughout the year. In reality, California renewable plants generated approximately 28,908 GWh in 2002.

[6] Costs for SCE’s existing renewables were mainly passed through to ratepayers under qualifying facility contracts.

[7] CPUC Decision 03-06-071, Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program, June 19, 2003, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/27360.htm], accessed July 28, 2004; California Energy Commission, *Renewables Portfolio Standard: Decision on Phase 2 Implementation Issues*, Commission Report, October 2003, 500-03-049F, [http://www.energy.ca.gov/portfolio/documents/2003-09-29_hearing/2003-10-21_COMSN_RPRT_PHSII.PDF], accessed July 28, 2004..

[8] CPUC, June 19, 2003, “Decision 03-06-071, Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program,” [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/27360.htm], accessed July 28, 2004..

[9] Ibid.

[10] National Wind Coordinating Committee, February 2002, *Credit Trading and Wind Power: Issues and Opportunities Resource Document*, [http://www.nationalwind.org/pubs/credit/ credit_wind.pdf], accessed July 27, 2004.

[11] California Public Utilities Code, § 399.13(b).

[12] California Energy Commission, October 2003, *Renewables Portfolio Standard: Decision on Phase 2 Implementation Issues*, Commission Report, October 2003, 500-03-049F, [http://www.energy.ca.gov/portfolio/documents/index.html], accessed July 28, 2004.

[13] National Association of Attorneys General, Resolution Adopting Environmental Marketing Guidelines for Electricity, Winter Meeting December 1-4 1999, [http://www.naag.org/issues/pdf/Green_Marketing_guidelines.pdf], accessed July 25, 2004.

[14] XENERGY, Inc. Contracting Team, December 2003, *Needs Assessment for the Western Renewable Energy Generation Information System, Final Report*, consultant report prepared for the California Energy Commission and Western Governors’ Association, 500-03-098F.

[15] PJM Interconnection is the independent regional transmission organization for all or part of the following: Illinois, Ohio, Pennsylvania, New Jersey, Delaware, Maryland, the District of Columbia, Virginia, and West Virginia.

[16] The New England Power Pool Generation Information System tracks all generation and creates certificates for both renewable and non-renewable generation.

[17] XENERGY, Inc. Contracting Team, December 2003, *Needs Assessment for the Western Renewable Energy Generation Information System, Final Report*,

consultant report prepared for the California Energy Commission and Western Governors' Association, 500-03-098F.

[18] http://www.westgov.org/wieb/wregis

[19] New England Power Pool Generation Information System, "Public Reports: GIS Certificate Statistics, Quarterly," [http://www.nepoolgis.com]. This source includes three quarters of data for 2002 and 2003 fuel by type, including biomass, digester gas, landfill gas, municipal solid waste, solar, trash to energy, and wind.

[20] Electric Reliability Council of Texas, "Renewable Energy Credit Program Information: Quarter/Annual Renewable Energy Generation in Texas by Technology Type," [http://www.texasrenewables.com], accessed July 25, 2004.

[21] Evolution Markets, "Renewable Energy: Renewable Energy Certificates," http://www.evomarkets.com/] and "Environmental Services Division: Renewable Energy Certificates," [http://www.natsource.com], accessed July 16, 2004.

[22] One possible explanation for this large price difference is that there is a relatively small amount of PV RECs available for sale and high consumer demand for this type of REC. Also, marketers may be interested in blending PV RECs into a mixed-REC product to attract consumers.

[23] Evolution Markets, *Voluntary REC Markets: Monthly Market Update, February 2004,* [http://www.evomarkets.com/assets/mmu/mmu_vrec_feb_04.pdf], accessed July 16, 2004.

[24] CPUC; *Opinion Adopting Standard Contract Terms and Conditions*; Appendix B, "2004 Annual Procurement Target" added together for SCE, SDG&E and PG&E; Decision 04-06-014, June 9, 2004.

[25] On September 20, 2001, the CPUC suspended the direct access market. After that date, new customers could no longer enter into direct access contracts to purchase electricity from an Electric Service Provider instead of their local utility. CPUC, Decision D.01-09-060.

[26] Bonneville Environmental Foundation Website, as of July 18, 2004, "Green Tag Customers," [https://www.greentagsusa.org/GreenTags/gt_cust_list.cfm].

[27] U.C. Santa Cruz Predatory Bird Research Group and California Energy Commission Public Interest Energy Research Program, April 2004, Grant Application Manual: Avian-Energy Systems Mitigation Program, [http://www.energy.ca.gov/contracts/third_party_funded/2004-05-26_PIERUCSC_RFP_GAM.PDF], accessed July 25, 2004.

CHAPTER 5: KEY POLICY ISSUES FOR DISTRIBUTED GENERATION PHOTOVOLTAIC ENERGY SYSTEMS

This chapter focuses on distributed PV generation incentive programs in California, performance-based incentives, policy options to encourage the use of PV in new homes, and caps on the level of net-metering that IOUs must accept.

Distributed PV generation offers consumers the ability to develop their own electricity supply, meeting a small portion of California's demand. From very modest levels of installed capacity in the early 1990s, the PV market has been growing rapidly in recent years. In his State-of-the-State address of 2004, Governor Schwarzenegger encouraged the use of PV in new homes.[1] If the demand for distributed PV generation continues to grow in California, economies of scale may cause the costs of PV to decline, creating a self-sustaining market. As discussed below, incentive programs in Japan and Germany have increased the number of installed PV systems and the installed system cost of PV has come down by about 25 percent in Germany and 35 percent in Japan. In California, from 1999 to 2003 prices for PV dropped about 13 percent for systems receiving rebates from the Emerging Renewables Program and the Self-Generation Incentive Program.[2]

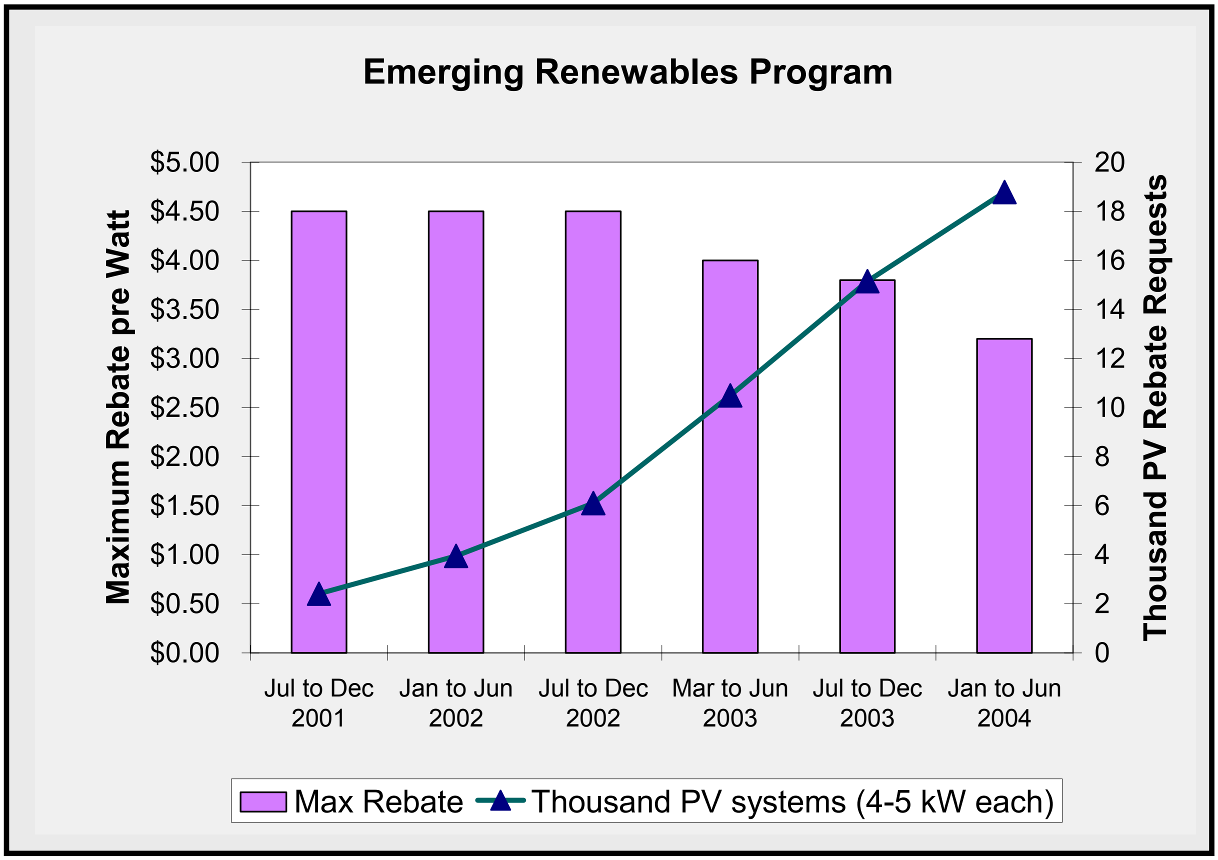
As discussed in Chapter 2, there are 16 incentive programs for renewable PV generation: the Self-Generation Incentive Program, incentive programs offered by 14 publicly owned electric utilities, and the Emerging Renewables Program.

Over-subscription of Photovoltaic Incentive Programs in California

The Emerging Renewables Program began offering cash rebates in March 1998 for projects less than 30 kW for electric customers of PG&E, SCE, SDG&E and Bear Valley Electric. The Emerging Renewables Program has supported over 9,600 installations of PV, representing nearly 38 MW, and has another 7,000 applications requesting funds or already reserved representing over 33 MW.

The Emerging Renewables Program was suspended from November 2002 until March 2003 because all available funds were allocated. Since then, the Emerging Renewables Program continues to be over-subscribed relative to its funding and administrative resources. Since March 2003, the Energy Commission has encumbered about five years worth of funding in just over a year and has reallocated funds from other Renewable Energy Program areas to prevent disruption of rebates for PV and small wind systems. As shown in Figure 10, demand has remained high, even though the rebates declined to $3.20/watt in January of 2004. It is anticipated that the Emerging Renewables Program will have allocated all available funds in the account by the end of the calendar year 2004.

Figure 10. Total Emerging Renewable Program Rebate Requests (July 2001- June 2004)



Source: Emerging Renewables Program

In 2001, following the Emerging Renewables Program, the CPUC began its Self-Generation Incentive Program, offering rebates for 30 kW to 1 MW of PV generation and other distributed generation capacity for gas and electric customers of PG&E, SCE, SDG&E, and the Southern California Gas Company. There is a total of $125 million per year available for rebates across three tiered levels. Approximately one-third of the funding goes to Level 1 technologies, with the remaining split between Level 2 and 3 technologies. Level 1 technologies include PV, wind, and renewable fuel cells. The amount of incentive available for Level 1 has remained at $4.50/watt or 50 percent of system costs.[3] As of July 2004, SCE had $3.8 million in available funds for Level 1 technologies through the Self-Generation Incentive Program, while PG&E, SDG&E, and the Southern California Gas Company had exhausted their 2004 Level 1 funds for renewable technologies.

In this year alone, the demand for rebates from PV system installations (Level 1) has increased dramatically, with applicants reserving $228.4 million from the Self-

Generation Incentive Program. Program administrators have exercised the discretion granted in D.01-03-073 to reallocate unencumbered funds from other incentive categories or administrative budgets, carrying forward unused funds from prior program years. Even so, as of May 31, 2004, SCE, Southern California Gas, and the San Diego Regional Energy Office combined had only $27 million Level 1 funds remaining. PG&E had a waiting list of Level 1 projects totaling 11.76 MW. More recently, data on the program administrators' websites indicates Level 1 applicants reserved additional funds in June 2004. The San Diego Regional Energy Office created a waiting list in late June and PG&E has a waiting list of over 100 proposed projects. If current demand continues, the Self-Generation Incentive Program will be out of funds before the end of the year.

As of the end of May, the Self-Generation Incentive Program reported supporting 114 installations representing 21 MW of PV currently installed in California.[4] There are another 443 PV projects representing 61 MW and 3 wind projects representing over 3 MW under review or with funding reserved.

The Emerging Renewables Program and the Self-Generation Incentive Program provide rebates to IOU customers. Households receiving gas service from an IOU and electric service from a publicly owned electric utility may have the opportunity to receive PV rebates from both the Self-Generation Incentive Program and their local electric utility.

There are 14 PV incentive programs offered by publicly owned electric utilities in California. Some of these programs began as recently as 2003. The two largest publicly owned electric utility PV incentive programs in California are offered by SMUD and LADWP. SMUD has been supporting PV since 1984, while LADWP began supporting PV in 1999. SMUD sells cost-reduced PV systems to its utility customers. LADWP offers a rebate of $4.50/Watt to its utility customers. If a utility customer uses PV panels manufactured in Los Angeles, the rebate level is $6.00/Watt.

Public Comments on Over-subscription of Photovoltaic Incentive Programs

At the June 8, 2004 workshop, the staff raised the issues of coordination of state and local incentive programs in California and possible phase-out of incentives for PV through the Emerging Renewables Program. Specifically, the questions on these topics were as follows:

1. How should state and local programs be coordinated in terms of incentives?
2. How formal or informal should this coordination be?

In general, stakeholders supported better coordination between state and local incentive programs for renewable distributed generation.

- The California Solar Energy Industries Association (CAL SEIA) indicated that they wanted to see coordination and consistency in how the Solar Rights Act is enforced in and across various jurisdictions.[5]

- The Natural Resources Defense Council argued that for PV policy to succeed in California, coordination was critical.[6]

- SDG&E indicated that incentive programs should strive to be structurally similar, but allow some local flexibility.

- PG&E supports a high level of coordination between incentive programs, including the Energy Commission and PG&E and CPUC. PG&E supports the Energy Commission's ability to respond to market conditions quickly and with flexibility.

Stakeholders were also asked to respond to the following questions on how to address over-subscription of the Emerging Renewables Program:

1. In California, are we achieving program goals of bringing about cost reductions so that we are close to reaching the point in time where incentives are no longer necessary?
2. What is the expected outlook in cost reductions for retail purchase of these distributed generation systems?
3. What could be done to accelerate reduction in costs of renewable distributed generation technologies? If additional funding is necessary to support renewable distributed generation technologies as costs are declining, how much support should be provided and for how long? What would be the source of funding?
4. What is the strategy of the PV and small wind industry if state incentive programs for their technologies are phased out?

In response, several stakeholders commented on these issues:

- CAL SEIA believes that additional funding is necessary, possibly through an increase in the public goods charge funds. This funding, regardless of the source, will be necessary for ten additional years before PV can be self-sustaining.[7]

- Environment California would support increasing the public goods charge funds for rebates to increase the amount of PV, thus continuing cost reductions to make PV affordable.[8] As noted below, Environment California is also a strong supporter for mandating the use of PV in a portion of new homes.

- Spectrum Energy commented that California's PV program has been too successful. Spectrum Energy termed the over-subscription of the Emerging

Renewables Program a "train wreck," already upon us because of the devastating impact it is likely to have on the PV industry.[9]

Further, several stakeholders commented on how to bring PV prices down. All agreed that long-term, consistent, simple rebate programs would bring about cost reductions.

- CAL SEIA argues that solar costs will only decline with long term policies and commitments. The "boom and bust" cycle is hurting the industry and keeping costs up.

- Under the Self-Generation Incentive Program, PG&E asserts that it has not seen the installed cost of PV decline noticeably over the last three years. From PG&E's perspective, the key to reducing PV costs is to have a long-term plan, including declining rebate levels.

- General Electric thinks that PV costs can decline and become commonplace *if* incentive programs are simple, long-term, consistent, and reliable.

- Kyocera states that to bring down costs, California must have a long-term plan and commitment to that plan.[10]

- Steve Heckeroth, attending the meeting at the request of Stan Ovshinsky, the inventor of thin film amorphous panels, argues that a "revolving loan program" would allow the money to be used many times, thus bringing down costs over a longer term than available to a one-time rebate program.[11]

The staff concurs that California's PV incentive programs should have greater coordination. While some incentive programs have declining rebate levels, others do not. For example, the Emerging Renewables Program has declining rebates and will offer $3.00/Watt for July-December 2004. The Self-Generation Incentive Program has been offering rebates of $4.50/Watt since 2001, but the incentive is likely to be reduced. The CPUC may develop a long-term plan for declining rebate levels for the Self-Generation Incentive Program in the coming months. Improved coordination could reduce gaps in funding and, therefore, support further market penetration of PV in California.

Next Steps for Photovoltaic Incentive Programs

Without changes in program designs or funding level, incentives for distributed PV generation in IOU service areas cannot be maintained at current subscription levels.

To avoid another deferral in Emerging Renewables Program funding, the staff is planning to study possible methods to ensure the long-term growth of the PV market and anticipates that a long-term plan for the Emerging Renewables Program will be developed and delivered to the Renewables Committee by September 1, 2004. This plan will be available for public review and comments at a publicly noticed workshop. The goal is to have funding in place and a revised program available by January 1, 2005.

To stretch limited funding, the CPUC recently released a report for public comment in which it considers lowering program incentive levels for some PV categories. The goal is to lower the incentive sufficiently to maximize peak demand reduction and decrease administrative complexity. Currently, the rebate is $4.50 per watt or 50 percent of project costs, whichever is less. The report proposes providing less than $4.50 per watt and removing the limit of 50 percent of project costs. The report also discussed a number of other proposed changes to the program. The CPUC plans to consider comments in drafting a proposed decision later this year.

Performance-based Incentives

The Energy Commission is investigating whether performance-based incentives may be a preferred method to achieve state goals.

Performance-based incentives have the potential to provide greater assurance that systems will perform well because PV owners are likely to put pressure on installers and marketers to ensure that their systems perform. This promotes the cost-effectiveness of public goods charge incentives for distributed generation PV in terms of long-term energy generation per dollar of incentive support.

In Germany, performance-based incentives are structured to tie the incentive level to the performance of the system in delivering electricity as measured in kWhs. The German model uses a “feed-in” law that requires the utilities to purchase PV generation at rates that have led to a significant number of installations of performance-based systems. These rates currently range from 55-75 US cents/kWh. Further detail regarding Germany’s PV market is discussed below.

Incentive programs can also mix funding tied to capacity with funding tied to energy performance. The Pennsylvania PV program is the primary example of the mixed capacity-and-performance model, and provides an up-front buydown of capital cost combined with a payment based on system performance after one year of operation. Another example is the Massachusetts PV incentive program, which offers a combination of an up-front incentive and a three-year performance-based incentive.

Programs which allow PV owners to sell their solar RECs for use to meet RPS requirements effectively include a performance-based element, although imposed by the commercial market rather than a public funding program.

Relative to capacity-based incentives, a performance-based incentive program has the potential to increase the financial impact of existing tax credits, because the net system capital cost is not decreased by an up-front rebate. This would shift more of the cost of the incentive from California ratepayers to federal and state taxpayers. For perspective, rebates in the state for PV systems totaled about $100 million in 2003, while claims for the state tax credit totaled about $5 million. A 7.5 percent state tax credit is available in 2004 and 2005; for businesses, the federal government offers a tax credit of 10 percent, and PV systems may be depreciated as a capital expense.

Yet, this incentive structure introduces new administrative difficulties. For example, performance data must be collected from each system with numerous payments made over an extended period of time for each program participant.

Public Comments on Performance-Based Incentives

Questions asked at the June 8, 2004 Energy Commission joint committee workshop regarding performance-based incentives were as follows:

1. Should the state pursue a strategy similar to the German model of providing incentives to produce renewable distributed generation, rather than incentives to install renewable generating systems?
2. If so, how should such a performance-based incentive program be structured and funded?
3. How would the state transition from the current incentive model, which is similar to the Japanese model, to a performance-based model similar to the German model?
4. Germany and Japan are the world leaders in installing distributed PV generation systems, followed by California. What lessons can California learn from these successes?

Several stakeholders commenting at the June 8, 2004 workshop supported performance-based incentives.

- CAL SEIA supports a performance based incentive pilot program in the Emerging Renewables Program. CAL SEIA wants the current Emerging Renewables Program rebate program to continue during this pilot phase.

- The Natural Resources Defense Council supports performance-based incentives for PV and believes the industry should move in that direction.[12]

- The League of Women Voters of California stated that performance standards were the “only way to go.”[13]

- Kyocera stated that before a performance based system is implemented in California, a pilot program is needed to test how the program would work and if customers would participate.[14]

- PG&E cautiously supports performance incentives because customers will monitor systems and "shop around" for the best installer. Also, with performance-based incentives, PG&E believes the system will stay in place longer. Finally, PG&E believes performance-based incentives would finally reward "tracker" systems. PG&E believes that any decision on this topic should clearly specify who will monitor the distributed generation output and who will pay for the monitoring.

- SDG&E states that all state renewable programs should work together, and thus, all should be based on performance (New/RPS, Existing, and Emerging).

The staff supports the idea of a performance-based incentive program provided that sufficient resources and access to performance monitoring data can be obtained. Currently, the staff does not believe there are sufficient funds to continue the capacity-based Emerging Renewables Program while conducting a pilot performance-based incentive program.

Next steps for Performance-Based Incentives

The staff plans to continue exploring possible development of a performance-based incentive program for the Emerging Renewables Program. One of the options under consideration in a revised program is a switch from capital cost rebates to performance-based incentives for PV distributed generation systems.

Policy Options for Photovoltaics in New Homes

This section compares PV markets in California, Japan, and Germany. The information suggests that a range of policy incentive options have proved successful for installing large amounts of PV and bringing the cost per system down over time. An important factor in the success of these programs is the cost of the PV system relative to retail electricity rates. Residential retail electricity rates in Japan and Germany are more than 20 cents/kWh and about 13 cents/kWh in California. After discussing PV markets in Japan and Germany, this section provides a review of a variety of policy options for accelerating the market penetration of PV.

A Comparison of Photovoltaic Markets in California, Japan, and Germany

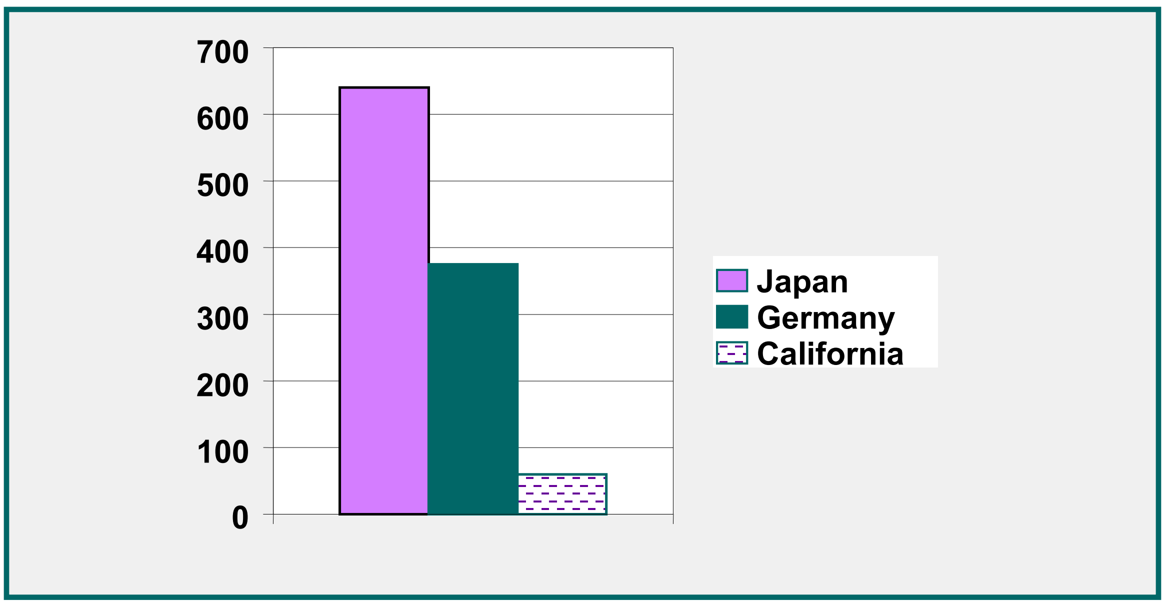
The three leading PV markets in the world are Japan, Germany, and California, in that order. All three have invested considerable public funds in developing their PV markets in recent years. Japan’s PV incentive program began in 1994, California’s in 1998, and Germany’s in 2000. Although insolation (i.e., intensity of sunlight) is stronger in California than in Japan or Germany, the demand for PV in Japan and Germany has been higher. The PV incentive programs in Japan and Germany have played a key role in establishing Japan and Germany as global leaders in installed PV systems.

At the end of 2003, cumulative installed PV systems in Japan, Germany, and California totaled 640 peak MW, 375 peak MW, and 60 peak MW, respectively (see Figure 11). Measured on a MW/capita basis, Japan has about 5.0 MW PV per million people, Germany about 4.6 MW PV per million people, and California about 1.8 MW PV per million people. In terms of 2003 gross domestic product, both Japan and Germany have about 150 MW PV per trillion US dollars gross domestic product, while California has less than 45 MW PV per trillion US dollars gross state product.[15]

To put this in perspective, the residential retail electricity rate in Japan and Germany is over 20 cents/kWh and about 13 cents/kWh in California.[16] Per capita electricity generation, including net imports in 2001 was about 8.2 MWh/year per capita in Japan, 6.6 MWh/year per capita in Germany, and 7.6 MWh/year per capita in California.[17]

Japan has become the leading global PV market using capital cost rebates. Japan requires minimum performance criteria as part of its capital cost rebate program. It is helpful to compare California's incentive programs with PV incentive programs in Japan and Germany to anticipate whether and how their experience can be used to inform decisions for PV policy in California.

Figure 11. Cumulative MW Photovoltaic Installed Year-End 2003



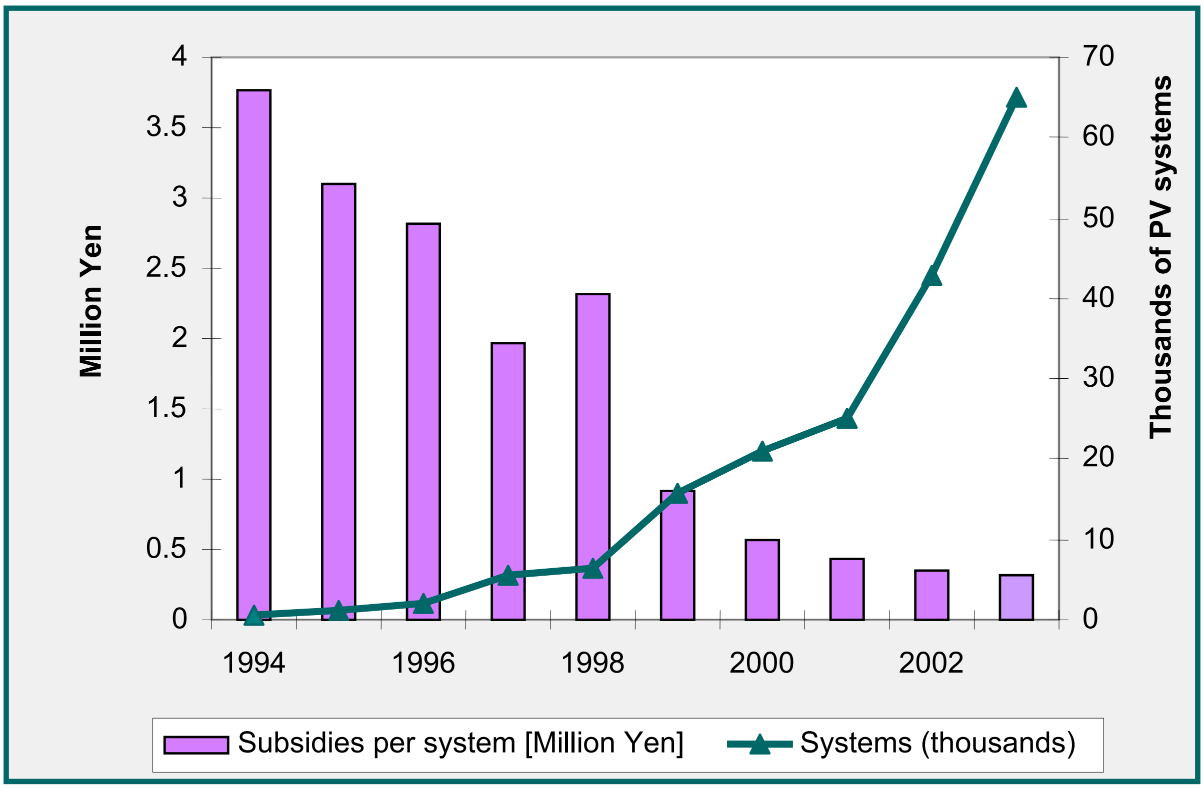
Source: Staff consultant comparative study of PV market development

Since 1994, Japan has spent over $1 billion in subsidies to decrease the capital cost and increase the market penetration of PV systems. The national capital subsidies in Japan will be phased out by the end of this year. Although the Emerging Renewable Program has been approving reservations at the rate of over $100 million per year over the past 16 months, California is behind Japan in terms of MW of PV and incentive levels.

In Japan, the price of PV systems dropped 35 percent from 1999 to 2003. In 2002, the price for a 3 kW PV system was about 2 million yen, which is about $5.60 per Watt before subsidies (assuming 120 Yen/dollar for 2002).[18] In 2002, the level of subsidy available was about 270,000 Yen for a 3 kW PV system, which is about $0.75 per Watt. As shown in Figure 12, the number of applications for PV subsidies in Japan increased from 500 in 1994 to an estimated 65,000 in 2003.[19]

The residential PV market in Japan is roughly half retrofit and half new construction. The new home market has a smaller number of companies that serve the majority of the market than in the United States. Japan also has more manufactured housing than in the United States, and prefabricated manufactured housing lends itself to PV.

Figure 12. Roof-top PV in Japan by Financial Year



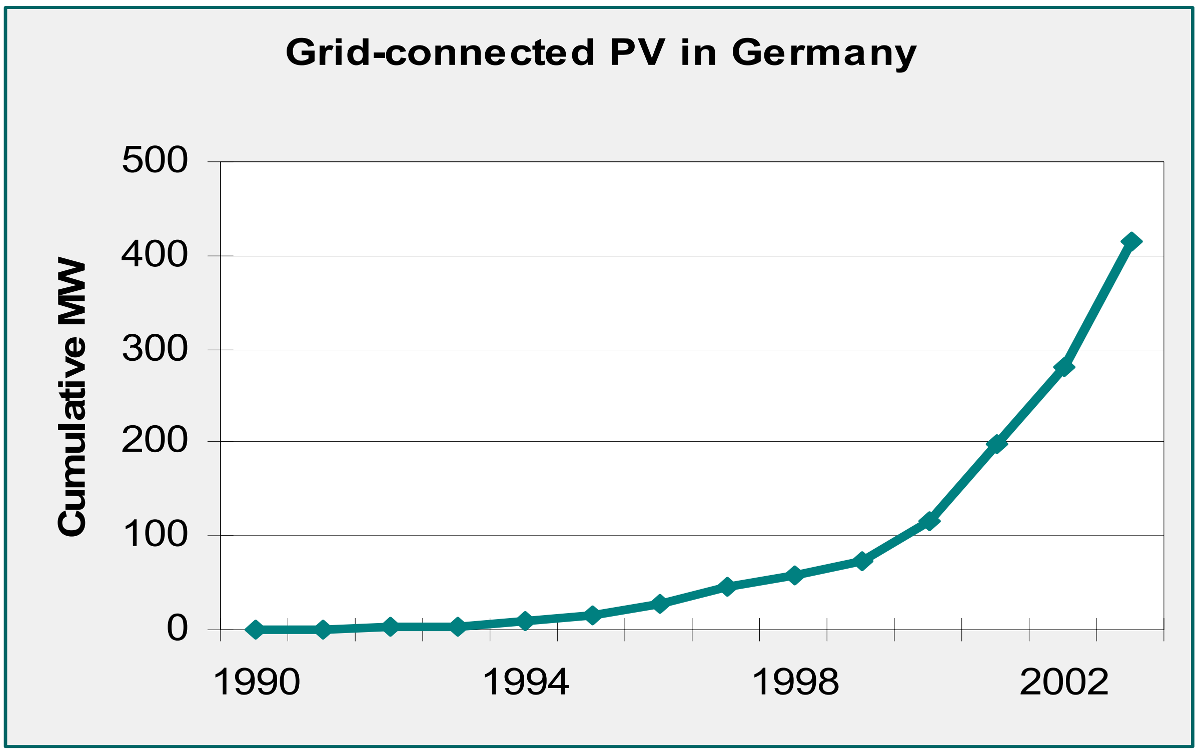
Source: Jagaer-Waldau Arnulf, 2003, *PV Status Report 2003: Research, Solar Cell Production and Market Implementation in Japan, USA and the European Union*, European Commission Directorate-General Joint Research Centre (EUR 20850EN), http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf]

Japan has also made significant investment in research and development on PV, spending $1.4 billion from 1993 through 2001. This investment has paid off, as about 45 percent of all PV sold in the world in 2002 was made in Japan.[20] At the June 8, 2004 workshop, Sharp Solar Systems Division reported that production builders in

Japan began to use PV in new home construction in 1997, with about 1.5 percent of new single-family homes built with PV in that year. Of about 350,000 new construction starts of single-family homes in 2002, almost 10 percent had PV.[21]

The German market for PV increased with the passage of the German Renewable Energy Sources Act, enacted in 2000. This act guarantees a fixed feed-in tariff (i.e., 55-75 US cents/kWh depending on the application) for electricity sent from the PV system onto the electricity grid. The payments continue for a 20-year period, but decline by 5 percent annually. This tariff requires that customers install the PV system on the utility side of their meter (as opposed to net-metering that offsets part or all of a customer's electric demand). The 100,000 Roof Program was a second German PV incentive program that offered low interest loans to consumers for PV systems. Under this program, which ended June 30, 2003, 345 MW of peak power were installed at a cost of $1.7 billion Euros.

Figure 13. Cumulative Grid-Connected PV in Germany (MW)



Source: German Solar Industry Association – Berlin (BSI), May 2004, "Solar Technologies from Germany," [http://www.german-renewable-energy.com/downloads/pdf/solar_germany.pdf].

The German feed-in tariff for PV provides an attractive incentive for electricity consumers to purchase and install PV systems. The cumulative installed PV capacity in Germany increased from about 60 MW in 1999 to about 375 MW in 2003 (see Figure 13). Over the same time period, the installed price of PV dropped 25 percent in Germany, compared to a 35 percent drop in Japan, and 13 percent price drop in California in the PV programs for IOU service areas. In 2002, the price of a 3 kW PV system in Germany was about 16,800 Euros (about $16,500, or $5.50/Watt).[22]

Other countries are also expanding their support for PV. Portugal has established a goal of 150 MW of PV by 2010 and, along with Spain, has substantially increased its feed-in tariffs this year to almost 60 cents/kWh.[23] China's five-year plan establishes a goal of achieving 300 MW of PV by 2005. China anticipates spending $1.2 billion to achieve its PV goal and is also looking to further increase its PV production capability.

In 2003, about 740 MW of PV were manufactured world-wide, up from 560 MW delivered in 2002.[24] Solar companies in California appear to be experiencing a shortage of solar panels in the state, primarily due to competition from Germany.[25] In the event of a shortage, the countries that have established a long-term commitment to PV and those that have invested in manufacturing facilities will be the first to receive the product. A number of leading manufacturers of PV panels have indicated plans to expand production capacity. Sharp Solar is increasing manufacturing capabilities from 248 MW to 315 MW.[26] Yet, despite the apparent shortage, PV panels in the United States cost less in July 2004 than July 2003.[27]

Potential Photovoltaic Policies for the New Home Market

A number of progressive builders have experience with building Zero Energy New Homes in the California housing market. Zero Energy New Homes use very little peak electricity from the electric grid because they use energy efficient building design, energy-saving technologies, and PV. Currently, the market for PV in new homes is small. Although approximately 130,000 new single-family homes are built in California each year, less than 500 of these new homes include PV.

However, in the case of Ladera Ranch, a developer mandate has led to 465 PV homes by ten builders. SMUD has used guaranteed rebates and significant utility support to reduce the risk and convince builders to construct Zero Energy New Homes. Clarum Homes includes PV as a core element of their enviro-home to differentiate itself from its competitors. The San Francisco Public Utilities Commission is leading the effort to develop 1600 Zero Energy New Homes at the Bayview Hunters Point Shipyard, a community with environmental justice concerns.

Much of the new home growth in California is located in the Central Valley and the inland areas of Southern California, where heavy air conditioning usage leads to peak load concerns. Incorporating PV into new residential construction provides several public policy benefits. Electricity generation from PV partially aligns with peak demand, which is of great value to California utilities. Electricity prices drop for all customers when the peak load is reduced.

PV energy in new homes has the potential to increase the effectiveness of available public goods charge funds for distributed generation PV incentives on a dollar per

MWh basis. The following list identifies some of the possible advantages from the perspective of cost-effectiveness:

1. Ability to roll costs into the mortgage – low cost financing
2. Potential for better building integration and aesthetics than retrofit market
3. Potential for greater installed cost reduction compared to retrofit market
4. Potential for better system performance due to installation scale economies

Increasing the use of PV in new homes faces a number of challenges, including the cost of a system, aesthetics, concerns about reliability and liability and, most importantly, delay in bringing the home onto the market. Possible causes of delay include plan check and inspections by building departments, utility interconnection, and inadequate supply of PV modules, inverters, or trained installers.

Based on available research and staff analysis, various policy options are outlined below for California to consider in expanding market penetration of PV. These options include both mandates and market incentives.

Builder Mandates

In the last few years, bills have been introduced in the California Legislature that would require builders to install PV on new homes in the state. In the current session legislation has been introduced that would require PV on at least 15 percent of new single family homes in developments of 25 homes or more by 2006 increasing by 10 percent each year until 2010.[28]

Mandating that builders install PV on new homes demonstrates to the PV manufacturing industry a long-term commitment and can also result in significant economies of scale for both the purchase of equipment and installation costs.

Requiring the use of PV on a portion of the new homes in California also introduces new challenges for builders. For example, a 2 kW PV system without a financial incentive can cost a builder up to $20,000 and add up to $30,000 to a home price. In addition, the use of PV in new homes can delay the completion of the home, which can further raise its cost. Delays can be caused by the availability of adequate PV product, local government plan check and inspections, and interconnecting to the utility. Access to trained subcontractors and PV installers can also be problematic.

Builder Incentives

In place of mandates, another policy option for increasing new homes with PV is to offer builder incentives. These could take the form of rebates or other types of incentives. For example, CAL SEIA has been in discussions with builders and PV manufacturers to facilitate purchase orders for a large number of PV systems in return for a price reduction from the PV manufacturers to the home builders.

The California Building Industry Association has suggested that builders would also be interested in “entitlements,” meaning incentives that can be offered through local government planning and permitting departments, such as reduced fees, expedited inspections and plan check, and liability protection.[29] Similarly, local governments could reduce developers’ infrastructure payments for new homes with PV. As local governments vary in staffing and budgets, the use of local incentives to encourage the use of PV is likely to be more successful in some cities than others.[30]

Providing incentives to builders has the potential to encourage cooperation by the builders and their subcontractors, economies of scale in purchasing, and better quality control in installation. Challenges with this approach are designing the incentive to encourage the use of PV in new homes, and assuming the continued decline in PV costs.

Consumer Finance

New financing mechanisms, such as a revolving loan fund for solar, could be attractive to consumers. Groups of lenders may also be persuaded to offer lower interest loans or reduction in points for new homes that include solar. Public purpose funds may be used to leverage this type of financing program, which could reduce the need for rebates. Lower interest rates could potentially attract homebuyers who may not be specifically in the market for a home with PV.

Utility Mandates

A utility could install PV on new residential construction in several ways. Utilities could offer rebates to builders and use utility bills as a mechanism to market their programs. The CPUC could mandate that the utilities serve as program administrators, similar to the role that they have with energy efficiency programs and the Self-Generation Incentive Program. An advantage to this approach is that utilities have established lines of communication with their customers.

The CPUC could also set a goal for PV, similar to the 20 percent by 2010 goal established for the RPS. The states of Arizona, New Jersey and Nevada have all developed such policies for PV as part of their RPS requirements.

Business Models for Zero Energy New Homes

Another policy option is to develop innovative business models for energy efficiency and PV in new homes, also known as “Zero Energy New Homes.” A new research effort will be launched by the Energy Commission later this year to address zero energy new homes, including innovative business models.

The Energy Commission is targeting research in the area of Zero Energy New Homes for California. Zero Energy New Homes brings together energy efficient building design and technologies, along with electricity generation from solar PV, to reduce peak electricity use to nearly zero in homes. The Energy Commission will be releasing a targeted solicitation to develop and demonstrate California optimized new zero energy home designs, business models, and public/private partnerships.

One of the goals of this effort is to accelerate the use of Zero Energy New Homes in California’s residential new construction market.[31] This will be achieved by developing new business models that may reduce or eliminate the initial cost of PV to homebuyers. New business models for PV can be created by facilitating innovative new business relationships among entities in the new home market, including builders, PV manufacturers, the financing and lending community, local governments, utilities, home buyers, and state government. A comprehensive stakeholder process will be used to develop a pilot program on these new models, which will be tested through an Energy Commission Zero Energy New Homes competitive solicitation planned in September 2004.

Public Comment on Photovoltaics in New Homes

At the June 8, 2004 workshop, public comment was requested regarding PV in residential new construction. To elicit discussion, the following questions were asked:

1. How should the state establish a program to foster installation of solar systems on new homes built in California? In particular:

    a) What should the near-term and long-term goals be for solar on new homes? Should the state establish numerical targets for these goals?
    b) Should mandates, incentives, or some other strategy be used to foster solar on new homes?
    c) What are the opportunities and barriers to increasing the market penetration of solar systems on new homes in California?
    d) To what extent would it be appropriate to modify California building codes to require new buildings to be solar ready? Should solar on new homes be mandated; if so, at what level, size, or percentage? What are the consequences of having a mandate for solar on new homes? Under what circumstances should a PV system qualify for compliance credits in

meeting the building energy efficiency standards? What are the consequences of such a credit?

e) What role can IOUs and publicly owned electric utilities play in delivering solar on new homes in their service areas?
f) What role can builders play in delivering solar on new homes to their customers?
g) How should a program for solar on new homes be coordinated with existing incentive programs, if at all?

Several stakeholders participating in the June 8, 2004 workshop on renewable distributed generation commented on general topics that provide a framework for further discussion.

- Spectrum Energy stated that the specific details of any program — be it rebate, production incentive, or new homes — are not as important as the credibility of the program. The industry must know that the program will be available for a certain amount of time and that funding will not delay projects seeking to participate in the program.[32]

- General Electric repeatedly stated that California's incentive program must be simple, long term, consistent, and reliable so that all stakeholders can plan and know what to expect.[33]

Many stakeholders participating in the workshop provided verbal and written comments on the state's solar policy. The majority of stakeholders support the concept of PV on new homes, though they are against mandating it.

The only stakeholder organization advocating a mandate for solar on new homes was Environment California.

- Environment California supported a minimum distributed generation/PV standard on new homes and is one of the leading supporters of Senator Murray's SB 1652, which would mandate partial PV on many new homes.

Those opposing a mandate for solar on new homes include the CAL SEIA, the California Building Industry Association, PG&E, and General Electric.

- CAL SEIA supported a strong commitment to installing solar on new homes, but favors incentives over mandates at this time.

- The California Building Industry Association stated that a mandate would seriously delay housing sales and raise prices because there are not enough PV panels and inverters to meet demand, there are not enough qualified installers, and there are not enough qualified inspectors. The mandate would hurt both the solar industry and the building industry.

- Both PG&E and General Electric supported incentives over mandates for PV on new homes.

While not clearly advocating a mandate for PV on new homes, the League of Women Voters stated that if there were a program for PV on new homes, it should apply statewide, including the publicly owned electric utilities.[34]

Several stakeholders at the June 8, 2004 workshop offered “non-mandate” ideas to promote solar on new homes.

- The League of Women Voters of California argued that education is the key to increasing PV. They suggested that the thought process of home buyers needs to be changed so that it is expected that PV comes with a new home.[35]

- The California Building Industry Association suggested the one or more economic “offsets” or “incentives” might encourage builders to install solar on new homes. For example, liability protection or permitting reforms could be used to entice builders to include solar on new homes.

- General Electric suggested that if builders can save money on entitlements, they can invest that into PV.[36]

- Both US Home and SDG&E indicated that Title 24 could be changed to encourage more solar.[37]

- Enercomp argued that for PV to earn Title 24 compliance credits, there should be some sort of third-party inspection to ensure that the PV is being installed correctly and sized appropriately.[38]

- In contrast, the Natural Resources Defense Council argued that PV should never qualify for compliance credits in meeting building energy efficiency standards under Title 24.[39]

The staff supports building on the success of existing PV incentive programs to further encourage PV in new homes. The goal of encouraging PV in new homes should be to further the state’s objective of market acceptance and cost reduction for PV.

The staff is exploring the technical feasibility of the policy options discussed above for PV in new homes. The June 8 workshop provided comments on the disadvantages of mandates for PV in new homes and industry support for incentives over mandates. A recent survey of public opinion in California reports that 82 percent of those participating in the survey support the goal of 15 percent of new homes running on partial solar power beginning 2006.[40] The staff notes that there is strong support for mandates for PV in new homes among environmentalists, and opposition from builders and building departments.[41] The staff notes that policy direction in this area should recognize the constraints facing funding for PV incentives.

Comments regarding economic offsets or incentives for builders should recognize that local governments have jurisdiction over much of this area. Local governments have indicated that they face resource constraints that limit the range of options they may consider.

Next Steps for Photovoltaics in New Homes

The staff plans to continue exploring the technical feasibility of options to encourage the use of PV in new homes.

Net Metering Caps

Assembly Bill 58 (AB 58, Chapter 836, Statutes of 2002, Keeley) expanded the net metering cap on individual projects from 10 kW up to one megawatt and eliminated the sunset provision where net metering for new customers was set to expire at the end of 2002.

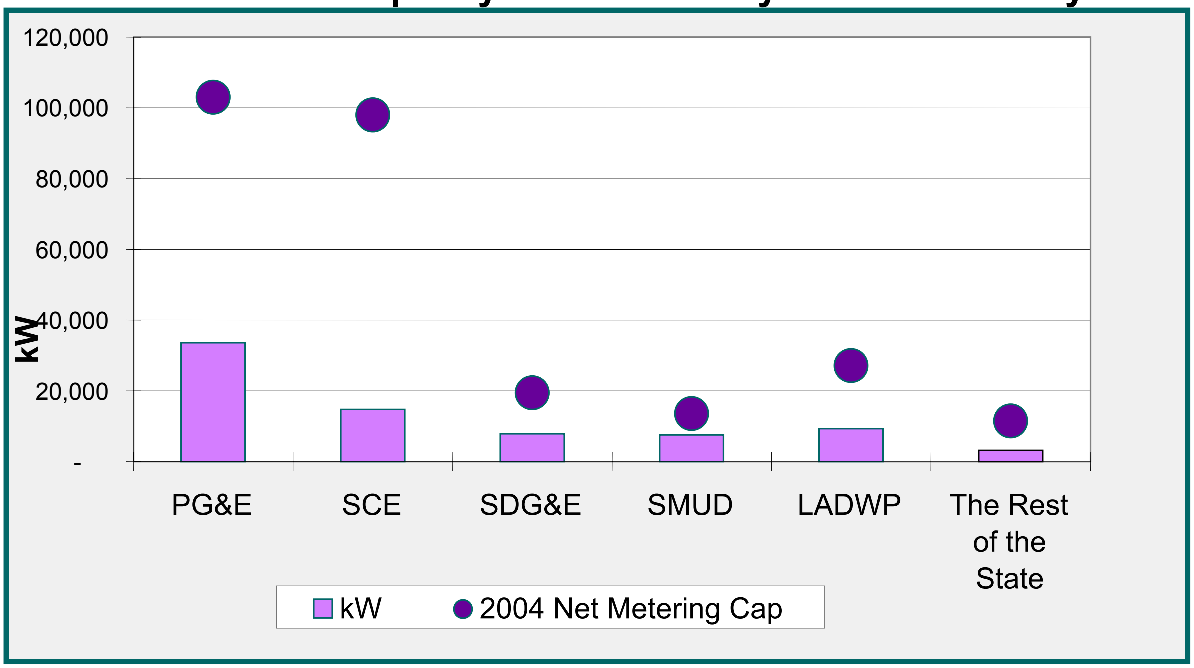
AB 58 also set a minimum net metering cap for each utility. Utilities are only required to offer net metering until the total rated generating capacity used by eligible customer-generators reaches one-half of 1 percent of the utility’s aggregate customer peak demand. Once the minimum threshold is reached, utilities can choose not to offer net metering to their customers. On the other hand, utilities can continue to offer their customers the option to net-meter once the minimum cap has been reached if the utility so chooses. Depending on the choice made by the utilities, the current cap of one-half of one percent could prevent achieving substantial penetration of PV on new homes. The cap may need to be increased to further the use of PV on new homes.

While AB 58 specifically exempts the LADWP, every other electrical utility in California, including publicly owned electric utilities, must comply with its provisions. Figure 14 below shows the estimated amount of net-metered capacity by utility and the 2004 estimated aggregate cap. As the load for each utility grows each year, the aggregate cap will increase correspondingly.

As Figure 14 illustrates, several of the utilities are close to the minimum aggregated cap. Again, once that cap is reached, the utility can prevent customers from establishing new net-metered accounts. This could have a serious dampening effect on the emerging PV markets. Also, the caps conflict with the stated goals of several cities. For instance, San Diego has a regional goal of 50 MW of PV. However, the minimum cap for SDG&E is approximately 19 MW. How city, county, and utility officials will resolve this discrepancy remains to be seen.

Although both PG&E and SCE appear to be far from the minimum net-metering cap, this is somewhat deceptive. When AB 58 took effect on January 1, 2003, PG&E had approximately 9.3 MW of net-metered PV capacity, while SCE had approximately 3.8 MW of net-metered PV capacity. Over the following 18 months, those capacities have grown to 34.1 MW for PG&E and 13.8 MW for SCE, a 250 percent increase for each utility. Assuming similar growth rates, PG&E could reach its minimum net-metered cap by 2008 and SCE could reach its minimum net-metered cap by 2013.

Figure 14. Estimated Net Metering Caps and Grid-Connected Photovoltaic Capacity in California by Service Territory



Source: "Amount (MW) of Grid-Connected Solar Photovoltaics (PV) in California, 1981 to Present and the California Energy Demand 2003-2013 Forecast (100-03-002)," [http://www.energy.ca.gov/renewables/emerging_renewables.html].

AB 58 mandated that the CPUC contract for a report to be delivered to the Governor and the Legislature by January 1, 2005, "that assesses the economic and environmental costs and benefits of net metering to customer-generators, ratepayers, and utilities, including any beneficial and adverse effects on public benefit programs and special purpose surcharges."

Once the CPUC report is delivered, the Legislature will be in a better position to assess whether new legislation is required to expand the minimum aggregate net-metering cap. Unless that cap is expanded, it is possible that the majority of Californians who install new PV systems will be unable to net-meter beginning in the next few years. Currently, it is unclear what policies the utilities have adopted with regard to the minimum net metering caps.

For owners of grid-connected distributed PV generation systems with net metering, the retail electricity rate design can significantly affect the net economic benefit of a PV system. This issue is discussed in the next section.

Retail Electricity Rate Design

The CPUC is considering whether and how to design a demand response rate for retail electricity. In particular, they are considering whether to require IOUs to offer retail electricity rates that more directly reflect the real-time costs of providing electricity to the consumer at times of heavy demand relative to times of low demand.

Currently, investor owned utilities offer time of use rates and net metering to renewable distributed generation systems including PV. Time-of-use rates are fixed ahead of time and set in relation to peak demand time-blocks. In contrast, real-time pricing reflects current prices to the IOU of purchasing wholesale electricity. Real-time pricing also reflects unanticipated supply problems and spikes in demand.

Real-time pricing is a critical component of demand reduction programs as well as an important enabling market mechanism for distributed generation. It can be important for PV systems because they generally produce electricity during California's peak demand. This is important for distributed PV generation policy because consumers with net metering receive credit at the rate applicable to the time their system generates electricity, and purchase electricity at the rate applicable to the time they consume electricity. Typically, distributed PV generation systems provide electricity on or near peak, when rates for electricity consumption are high. In contrast, these consumers show net consumption of electricity when retail rates for electricity are low.

In order to participate in a real-time pricing system, consumers need a special electricity meter. Many PV system owners install a time-of-use meter to take advantage of currently available time-of-use rates. However, time-of-use meters and interval meters (used for real-time pricing) are different.

Typically, time-of-use meters have fixed time intervals (e.g., 5 different time periods throughout the day). Consumption is aggregated under each time interval (e.g., peak, shoulder peak, and non-peak). Interval meters, on the other hand, measure consumption levels in finer detail; they have variable intervals and can read minutes. For real-time pricing, this would most likely be 15-minute intervals.

Public Comment on Net Metering Caps

At the June 8, 2004 workshop, public comment was requested regarding net metering caps. To elicit discussion of this topic, the following questions were asked:

1. Should the caps or expectations on these policies be re-examined in light of the strong recent demand? What opportunities and problems would this be likely to create?
2. What is the status of net metering in California? Which utilities are coming close to the cap? When do they expect to reach it? What policies are they planning to adopt once the cap is reached?
3. Should incentives be adopted to encourage utilities to allow additional net metering beyond the cap set in AB 58? What type/level of incentives would you recommend?

Several stakeholders commented verbally or in writing at the June 8, 2004 workshop regarding the net metering caps. Some supported lifting all net metering caps, while others argued that there needs to be some analysis of the costs and benefits of net metering before any changes are made.

Those favoring raising or eliminating the net metering caps include CAL SEIA, the League of Women Voters of California and the Rahus Institute.

- CAL SEIA stated that the aggregate net metering cap should be completely eliminated to encourage high-density, transmission constrained communities (e.g., San Diego, Oakland, and San Francisco) to invest in solar.

- The League of Women Voters of California sees no reason for limitations in terms of the overall net metering cap or in terms of the capacity of individual systems.[42]

- The Rahus Institute stated that if California is to greatly expand the number of new homes with PV, then the net metering caps will need to be raised.[43]

Those favoring more analysis include PG&E and SDG&E.

- PG&E argued that the aggregate net metering cap should not be expanded until a cost-benefit analysis has been conducted and shown to be beneficial to other ratepayers. PG&E does not have a policy in place once the net metering aggregate cap is reached (because it is somewhat far off).

- SDG&E submitted comments to the CPUC on May 17, 2004 regarding net metering. Those comments recommended that the CPUC work through its cost benefit analysis proceedings to determine as quickly as possible what is in the best interests of SDG&E's ratepayers and adjust the net metering program accordingly.

Consistent with CAL SEIA's comments, the staff recognizes that net metering provides an incentive for the installation of PV. Real-time pricing discussions are underway. Depending on the pricing signals, this rate may provide a further incentive for PV owners to utilize net metering with their systems.

The staff is collaborating with the CPUC regarding assessment of the costs and benefits of distributed generation. The staff believes the results of the January 2005 report and activities in the CPUC and Energy Commission distributed generation proceedings are important for considering changes in the net metering program, but interim changes may be needed soon.

Next Steps on Net Metering Caps

The staff believes an interim decision by the CPUC regarding the net metering cap in San Diego is needed before the cap is reached. The January 2005 report should be available before this occurs, but the staff believes it is possible that San Diego could reach the cap in 2005 or 2006.

Notes

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[2] This uses completed systems to date by year applications were received. This data will change as pending projects become completed. This number was calculated using a weighted average of data from the Emerging Renewables Program database on July 27, 2004 and San Diego Regional Energy Office, June 20, 2004, "Statewide SELFGEN Projects to date: Level 1," [http://www.sdenergy.org/uploads/SelfGen_Statewide_Data%20_June04.xls], accessed July 27, 2004. For data on the Emerging Renewables Program (updated monthly), see California Energy Commission, "Data Regarding Number of Completed Systems," [http://www.energy.ca.gov/renewables/ emerging_renewables.html], accessed July 28, 2004.

[3] See "Financial Incentives for Solar Energy." [http://www.californiasolarcenter.org/incentives.html], accessed July 9, 2004.

[4] About 9 MW of PV supported by the Self-Generation Incentive Program are for Southern California Gas customers receiving electricity from LADWP.

[5] Jan McFarland, CAL SEIA, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 187.

[6] Sheryl Carter, Natural Resources Defense Council, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 156-160.

[7] Jan McFarland, CAL SEIA, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 190-192.
[8] Bernadette del Chiaro, Environment California, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 200-201.
[9] Don Osborn, Spectrum Energy, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 152-155.
[10] Cecilia Aguillon, Kyocera, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 194.
[11] Steve Heckeroth, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 198.
[12] Sheryl Carter, Natural Resources Defense Council, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 156-160.
[13] Jane Turnbull, League of Women Voters of California, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 160-164.
[14] Cecilia Aguillon, Cyocera, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 241.
[15] World Bank, "Total GDP 2003," [http://www.worldbank.org/data/databytopic/GDP.pdf], accessed July 8, 2004.
[16]. Jagaer-Waldau Arnulf, 2003, *PV Status Report 2003: Research, Solar Cell Production and Market Implementation in Japan, USA and the European Union*, European Commission Directorate-General Joint Research Centre (EUR 20850EN), [http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf]. Residential electricity rates in 2003 in California for the major utilities were as follows: PG&E 12.87 cents/kWh, SCE 13.46 cents/kWh, SDG&E 14 cents/kWh, LADWP 10.44 cents/kWh, SMUD 10.20 cents/kWh, and municipalities of Burbank, Glendale, and Pasadena 12.73 cents/kWh. See Energy Commission, July 7, 2004, "2003 California Average Retail Electricity Rates by Major Utility." [http://www.energy.ca.gov/electricity/current_electricity_rates.html].
[17] Population estimate for Germany and Japan is from *The Economist Pocket World in Figures 2004 Edition (Uses YE 2001 Data)*. Population estimate for California is from the 2002 U.S. Census. Information regarding Japan and Germany electricity generation is from the U.S. Central Intelligence Agency, *The World Factbook 2004*, updated as of May 11, 2004. [http://www.cia.gov/cia/publications/factbook/], accessed June 24, 2004. Information regarding California is from California Energy Commission, July 2003, "California Electricity Generation 1983 to 2002, Total Production by Resource Type," [http://www.energy.ca.gov/electricity/index.html#generation], accessed June 24, 2004.
[18] Actual Yen/dollar exchange rates for 2002 ranged from about 133 Yen/dollar in January, to about 120 Yen/dollar for the latter part of the year. See U.S. Federal Reserve, "Statistical Release H.10 Foreign Exchange Rates (Weekly)," [http://www.federalreserve.gov/releases/H10/], accessed June 24, 2004.
[19] Jagaer-Waldau Arnulf, 2003, *PV Status Report 2003: Research, Solar Cell Production and Market Implementation in Japan, USA and the European Union*, European Commission Directorate-General Joint Research Centre (EUR 20850EN),

[http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf], accessed July 16, 2004.

[20] Jagaer-Waldau Arnulf, 2003, *PV Status Report 2003: Research, Solar Cell Production and Market Implementation in Japan, USA and the European Union*, European Commission Directorate-General Joint Research Centre (EUR 20850EN), [http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf], accessed July 16, 2004.

[21] Presentation by Aaron Nitzkin, Sharp Solar Systems Division, at the June 8, 2004 Energy Commission joint committee workshop on accelerated renewable energy development (renewable distributed generation), [http://www.energy.ca.gov/2004_policy_update/documents/2004-06-08_workshop/2004-06-08_SHARP.PDF], accessed June 24, 2004.

[22] Frank Stubenrauch, May 2003, *International Energy Agency Co-operative Programme on Photovoltaic Power Systems Task 1 (Exchange and Dissemination of Information on PV Power Systems): National Survey Report of PV Power Applications in Germany 2002*, prepared on behalf of the German Federal Ministry of Economy and Technology, [http://www.oja-services.nl/iea-pvps/nsr02/download/deu.pdf], accessed July 16, 2004. Actual Euro/dollar exchange rates for 2002 ranged from about 0.87 Euro/dollar in February, to about 1.0081 Euro/dollar in December. See U.S. Federal Reserve, “Statistical Release H.10 Foreign Exchange Rates (Weekly),” [http://www.federalreserve.gov/releases/H10/], accessed July 16, 2004

[23] “Spain’s Renewables Tariffs a ‘Saviour’ to all but Biomass,” *Renewable Energy World*, May-June 2004. The subsidy for PV in Spain in 2004 is 0.49 Euro/kWh. Using a conversion factor of 0.83 Euro/$ results in $0.59/kWh.

[24] Paul Maycock, *PV News,* 2003 and March and April 2004, as cited in “PV Manufacturing Booms,” Renewable Energy World, May-June 2004, page 18; and Jagaer-Waldau Arnulf, 2003, *PV Status Report 2003: Research, Solar Cell Production and Market Implementation in Japan, USA and the European Union*, European Commission Directorate-General Joint Research Centre (EUR 20850EN), p. 4, [http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf], accessed July 16, 2004.

[25] “State Solar Installers Scrounge for Panels,” *California Energy Circuit*, Vol. 2 No. 24, June 18, 2004.

[26] “State Solar Installers Scrounge for Panels,” *California Energy Circuit*, Vol. 2 No. 24, June 18, 2004.

[27] Solarbuzz, “Solar Module Price Highlights – July 2004,” [http://www.solarbuzz.com/ModulePrices.htm], accessed July 21, 2004.

[28] Senate Bill 1652 (SB 1652, under consideration, Statutes of 2004), June 29, 2004 version of the bill, [http://www.leginfo.ca.gov/pub/bill/sen/sb_1651-1700/sb_1652_bill_20040629_amended_asm.pdf], accessed July 25, 2004.

[29] Bob Raymer, California Building Industry Association, docketed comments in response to the California Energy Commission’s June 8, 2004 workshop regarding Renewable Distributed Generation.

[30] The staff contractor conducted interviews with builders and local government personnel to assess the feasibility of offering entitlements in exchange for a modest financial contribution of public funds. The local governments participating in the study included City and County of San Francisco, City of Oakland, City of Palo Alto, City of Pleasanton, City of San Jose, City of Santa Monica, City of Sunnyvale, County of San Mateo, Local Government Commission, San Diego Regional Energy Office, and the San Francisco Public Utilities Commission. For the most part, staff from local governments participating in the study indicated that they do not think that review, inspections, and process times could be reduced for homes that include PV. Budget cuts and the resulting staff reductions in the local government have made it almost impossible to offer expedited service to selected clients. The modest contribution of public funds would not be adequate to cover implementation costs. This was especially true for the growing cities that have substantial new home developments. These local governments are already stretched and offering expedited service is not currently feasible.

[31] Navigant Consulting, Inc. is supporting the California Energy Commission in addressing one of the primary barriers to incorporating PV into new homes – up-front cost.

[32] Don Osborn, Spectrum Energy, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 152-155.

[33] Dave Nyberg, GE Energy, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 70.

[34] Jane Turnbull, League of Women Voters of California, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 261.

[35] Jane Turnbull, League of Women Voters of California, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 239.

[36] Dave Nyberg, GE Energy, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 204-205.

[37] 2001 Title 24, Part 6 California's Energy Efficiency Standards for Residential and Nonresidential Buildings, [http://www.energy.ca.gov/title24/index.html], accessed July 25, 2004.

[38] Ken Nittler, Enercomp, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 170-182.

[39] Sheryl Carter, Natural Resources Defense Council, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 156-160.

[40] Mark Baldassare, July 2004, *PPIC Statewide Survey: Special Survey on Californians and the Environment*, Public Policy Institute of California, [http://www.ppic.org/main/pubs.asp], accessed July 24, 2004.

[41] According to the bill analysis provided by the California state assembly, supporters of the bill include the following: Environment California (Sponsor), Bluewater Network (San Francisco), California Public Interest Research Group, Clarum Homes (Palo Alto), Clean Power Campaign, Coalition for Clean Air (Los Angeles), Coalition on the Environment and Jewish Life of Southern California, Committee to Bridge the Gap (Los Angeles), Connect Energy (Grass Valley), East Bay Municipal Utility District, E-Loan, Inc., Global Green USA, Intex Solutions, Inc.

(Montebello), Los Angeles Interfaith Environmental Council, Physicians for Social Responsibility (Los Angeles), Planning and Conservation League, Rainforest Action Network (San Francisco), Sierra Club California, South Coast Air Quality Management District, Union of Concerned Scientists (Berkeley), Utility Reform Network, Vote Solar Initiative (San Francisco). Opponents of the bill include: American Institute of Architects California Council, California Apartment Association, California Association of Realtors, California Building Industry Association, California Building Officials, California Business Properties Association, California Chamber of Commerce, California Engineers and Land Surveyors, California Manufacturers and Technology Association, City of Moreno Valley, Home Ownership Advancement Foundation, League of California Cities. See California Assembly Committee on Housing and Community Development, June 22, 2004, “SB 1652 Bill Analysis,” [http://www.leginfo.ca.gov/pub/bill/sen/sb_1651-1700/sb_1652_cfa_20040622_091822_asm_comm.html], accessed July 28, 2004.

[42] Jane Turnbull, League of Women Voters, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Pages 160-164.

[43] Tor Allen, The Rahus Institute, Transcript of the June 8, 2004 workshop on Renewable Distributed Generation, Page 246.

ACRONYMS

CA ISO	California Independent System Operation
CAL SEIA	California Solar Energy Industries Association
CCA	community choice aggregator
CPUC	California Public Utility Commission
Energy Commission	California Energy Commission
ESP	electric service provider
GWh	gigawatt hour
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor-owned utility
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
MPR	market price referent
MW	megawatts
MWh	megawatt hour
PG&E	Pacific Gas and Electric Company
PV	photovoltaics
REC	renewable energy certificate
RPS	renewables portfolio standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEPs	supplemental energy payments
RPS	Renewables Portfolio Standard
SMUD	Sacramento Municipal Utility District
TREC	tradable renewable energy certificate
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

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APPENDICES

Appendix A. Estimated Energy Requirements to Meet the Renewables Portfolio Standard by 2017 and the Accelerated Renewables Portfolio Standard by 2010

Appendix B. Renewables Portfolio Standard Procurement Process for IOUs

Appendix C. Summary of Public Comments from the May 4, 2004 and June 8, 2004 Committee Workshops on Accelerated Renewable Energy Development (Central-Station and Distributed Generation)

Appendix D. Summary of Public Comments from the October 20, 2003 California Public Utilities Commission-California Energy Commission Collaborative Staff Data Request: Inviting Comments on Renewable Distributed Generation in the Renewable Portfolio Standard Program

Appendix A. Estimated Energy Requirements to Meet the Renewables Portfolio Standard by 2017 and the Accelerated Renewables Portfolio Standard by 2010

Appendix A summarizes the major assumptions that the staff used to estimate the energy requirements needed to meet the statewide RPS and the accelerated RPS, including the retail sales forecast. There are four items in this appendix:

- Estimation of Energy Requirements to meet California's RPS by 2017
- Estimation of Energy Requirements to meet California's RPS by 2010
- Staff 2003-2013 Demand Forecast – Updated June 2004: Retail Sales by Utility (GWh)
- Notes regarding the preparation of the staff estimate of California retail sales

Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1			Staff's Outlook for California - Retails Sales by Utility (GWh). Updated June 2004. Lynn Marshall. Energy Commission's Demand Analysis office through 2013. Staff projected out to 2017 based on (1a)														2014-2017 sales figures assumed at "Annual Growth Rate" of 2003-2013				1a - RATE
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
3	1	Sales (GWh)	**PG&E**	75,681	70,861	71,224	72,496	74,205	75,748	76,879	78,530	79,535	80,751	81,814	82,812	83,569	84,915	86,283	87,674	89,086	**1.61%**
4			**SCE**	74,286	68,427	70,617	72,136	73,687	75,272	76,892	78,546	79,504	80,520	81,734	82,967	83,747	85,188	86,653	88,144	89,660	**1.72%**
5			**SDG&E**	15,000	14,301	15,040	15,363	15,693	16,029	16,373	16,724	16,985	17,213	17,461	17,763	17,945	18,264	18,590	18,921	19,258	**1.78%**
6			**Total**	164,967	153,589	156,881	159,995	163,585	167,049	170,143	173,800	176,024	178,484	181,008	183,541	185,261	188,368	191,526	194,738	198,004	
7																					
8			Grand Total Statewide Sales	242,861	246,910	254,442	258,858	263,924	268,784	273,213	278,238	281,616	285,399	289,250	293,077	296,061	300,580	305,169	309,827	314,556	1.53%
9			DA and Rest of State	77,895	93,322	97,562	98,864	100,338	101,734	103,070	104,438	105,591	106,915	108,241	109,536	110,800	112,213	113,642	115,089	116,552	1.28%
10			**PG&E DA**	3,761	7,433	8,979	9,076	9,173	9,272	9,372	9,473	9,597	9,722	9,848	9,977	10,108	10,228	10,350	10,473	10,598	1.19%
11			**SCE DA**	4,168	11,234	11,571	11,728	11,887	12,048	12,212	12,377	12,580	12,785	12,995	13,207	13,424	13,625	13,829	14,036	14,246	1.50%
12			**SDG&E**	2,463	3,448	3,322	3,383	3,445	3,508	3,572	3,637	3,718	3,801	3,885	3,972	4,060	4,143	4,227	4,312	4,400	2.03%
13			**Total DA**	10,392	22,115	23,871	24,186	24,505	24,828	25,156	25,488	25,894	26,308	26,728	27,156	27,592	27,995	28,405	28,821	29,243	1.46%
14			**Total Rest of State**	67,503	71,207	73,690	74,678	75,833	76,906	77,914	78,950	79,697	80,608	81,513	82,380	83,209	84,217	85,237	86,268	87,309	1.22%
15			**DA % of non IOU**	13.34%	23.70%	24.47%	24.46%	24.42%	24.40%	24.41%	24.40%	24.52%	24.61%	24.69%	24.79%	24.90%	24.95%	25.00%	25.04%	25.09%	
16			**Rest of State % of non IOU**	86.66%	76.30%	75.53%	75.54%	75.58%	75.60%	75.59%	75.60%	75.48%	75.39%	75.31%	75.21%	75.10%	75.05%	75.00%	74.96%	74.91%	
17																					
18			Percent IOU sales	67.93%	62.20%	61.66%	61.81%	61.98%	62.15%	62.27%	62.46%	62.51%	62.54%	62.58%	62.63%	62.58%	62.67%	62.76%	62.85%	62.95%	
19			Percent DA	4.28%	8.96%	9.38%	9.34%	9.28%	9.24%	9.21%	9.16%	9.19%	9.22%	9.24%	9.27%	9.32%	9.31%	9.31%	9.30%	9.30%	
20			Percent Rest	27.79%	28.84%	28.96%	28.85%	28.73%	28.61%	28.52%	28.37%	28.30%	28.24%	28.18%	28.11%	28.11%	28.02%	27.93%	27.84%	27.76%	
21																					
22	2	2001 Base-line	THIS IS CHANGEABLE	2001 GWh	2001%		2002 GWh	2002%	2003 GWh	2003%											
23			**PG&E**	6,719	8.88%	3.52%	7,392	10.43%	8,828	12.39%		This is for a 14 year total (accounts for 2003 Interim Procurement)									
24			**SCE**	11,364	15.30%	2.82%	12,018	17.56%	12,791	18.11%		**20% Goal**	**Minus Baseline**	**vg. GWh Yr**	**MW/Year**	**MW/Year**					
25			**SDG&E**	146	0.97%	2.68%	141	0.99%	550	3.66%		Take 20%	Base and 2003	Divide by 14	**50 % CF**	**55 % CP**					
26			**Total**	18,229	11.05%							5,848.66	5,848.66	417.76	**95**	**87**	**DA no baseline**				
27												5,848.66	3,898.37	278.45	**64**	**58**	**DA w/ baseline**				
28		7.17%	**PG&E DA**	270	7.17%																
29			**SCE DA**	299	7.17%							17,461.78	9,255.76	661.13	151	137	**Rest of State**				
30			**SDG&E**	177	7.17%							39,600.81	17,431.92	1,245.14	284	258	IOU				
31			**Total DA**	745	7.17%																
32																					
33			**Total DA and IOU Baseline**	18,974																	
34																					
35			**Total Rest of State**	6,842	10.14%							This is for a 15 year total (baseline only)									
36												**20% Goal**	**Minus Baseline**	**vg. GWh Yr**	**MW/Year**	**MW/Year**					
37			**J-11 Figure**	25,816								Take 20%	Base only	Divide by 15	**50 % CF**	**55 % CP**					
38												5,848.66	5,848.66	389.91	**89**	**81**	**DA no baseline**				
39												5,848.66	5,103.56	340.24	**78**	**71**	**DA w/ baseline**				
40																					
41												17,461.78	10,619.78	707.99	162	147	**Rest of State**				
42												39,600.81	21,372.04	1,424.80	325	296	IOU				
43																					
44	3	**1% Minimum Percentage Point Growth (capped) as percent**		[% shown in (Section 2)] + [1%] up to [20%].																	
45			**PG&E**			9.88%	10.88%	11.88%	12.88%	13.88%	14.88%	15.88%	16.88%	17.88%	18.88%	19.88%	20.00%	20.00%	20.00%	20.00%	
46			**SCE**			16.30%	17.30%	18.30%	19.30%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
47			**SDG&E**			1.97%	2.97%	3.97%	4.97%	5.97%	6.97%	7.97%	8.97%	9.97%	10.97%	11.97%	12.97%	13.97%	14.97%	15.97%	
48			**Total**			12.01%	13.01%	14.01%	15.01%	15.88%	16.43%	16.98%	17.52%	18.07%	18.62%	19.17%	19.32%	19.41%	19.51%	19.61%	
49																					
50			**PG&E DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
51			**SCE DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
52			**SDG&E**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
53			**Total DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	
54																					
55			**Total Rest of State**			11.14%	12.14%	13.14%	14.14%	15.14%	16.14%	17.14%	18.14%	19.14%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	
56																					

2004 20-2017

Shading with text is explanatory.
Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
57	4	1% Minimum Percentage Point Growth (capped) as GWh		(Section 3) * (Section 1).																	
58			PG&E			7,036	7,887	8,815	9,755	10,670	11,684	12,629	13,630	14,627	15,634	16,612	16,983	17,257	17,535	17,817	
59			SCE			11,508	12,477	13,483	14,525	15,378	15,709	15,901	16,104	16,347	16,593	16,749	17,038	17,331	17,629	17,932	
60			SDG&E			297	457	623	797	978	1,166	1,354	1,544	1,741	1,949	2,148	2,369	2,597	2,833	3,076	
61			Total			18,841	20,821	22,921	25,078	27,026	28,559	29,884	31,278	32,715	34,176	35,510	36,390	37,185	37,996	38,825	
62																					
63			PG&E DA			734	832	933	1,036	1,141	1,248	1,360	1,475	1,592	1,713	1,837	1,961	2,070	2,095	2,120	
64			SCE DA			945	1,075	1,209	1,346	1,486	1,630	1,783	1,940	2,101	2,268	2,439	2,612	2,766	2,807	2,849	
65			SDG&E			271	310	350	392	435	479	527	577	628	682	738	794	845	862	880	
66			Total DA			1,950	2,218	2,492	2,773	3,061	3,357	3,669	3,991	4,322	4,663	5,013	5,367	5,681	5,764	5,849	
67																					
68			Total Rest of State			8,206	9,063	9,961	10,871	11,793	12,739	13,657	14,619	15,598	16,476	16,642	16,843	17,047	17,254	17,462	
69																					
70	5	Additional Energy (GWh) Per Year on top of Baseline		For 2003, (Section 4) - (Section 2). For other years, (Section 4 current year) - (Section 4 prior year)																	Total Add'tl Ene
71			PG&E			317	851	928	941	914	1,015	945	1,001	998	1,007	979	371	274	278	283	11,098
72			SCE			145	969	1,005	1,043	853	331	192	203	243	247	156	288	293	298	303	6,568
73			SDG&E			151	160	167	174	181	188	188	190	197	208	199	221	228	235	243	2,930
74			Total			612	1,980	2,100	2,157	1,948	1,534	1,325	1,394	1,437	1,461	1,334	880	795	812	829	20,596
75																					
76			PG&E DA			464	99	101	103	105	107	112	115	118	121	123	124	109	25	25	1,850
77			SCE DA			647	130	133	137	140	144	152	157	162	166	171	173	154	41	42	2,550
78			SDG&E			95	39	40	41	43	44	48	50	52	54	56	56	51	17	17	703
79			Total DA			1,205	268	274	281	288	295	312	322	331	341	351	353	314	83	84	5,104
80																					
81			Total Rest of State			1,364	857	899	910	922	946	918	962	979	878	166	202	204	206	208	10,620
82																					
83	6	Needed or Known Growth - percent (total) - if NOT at 20% by 2017 with simple 1 % growth		Shaded highlights represent known Procurements. Otherwise, if not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2017. If percentage drops over time, this is because the IOU procured more in one year than they were required to, so they are "banking" it forward. The percentage will increase once procurements start again.																	Annual Avg. Growth Rate if not at 20% by 2017 at 1%
84			PG&E			12.39%	12.39%	12.39%	12.88%	13.88%	14.88%	15.88%	16.88%	17.88%	18.88%	19.88%	20.00%	20.00%	20.00%	20.00%	0.00%
85			SCE			18.11%	18.11%	18.30%	19.30%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	0.00%
86			SDG&E			3.66%	3.66%	4.78%	6.05%	7.31%	8.58%	9.85%	11.12%	12.39%	13.66%	14.93%	16.19%	17.46%	18.73%	20.00%	1.27%
87			Total			14.13%	14.13%	14.32%	15.12%	16.01%	16.59%	17.16%	17.73%	18.31%	18.88%	19.45%	19.63%	19.75%	19.88%	20.00%	
88																					
89			PG&E DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
90			SCE DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
91			SDG&E			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
92			Total DA			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%	16.17%	17.17%	18.17%	19.17%	20.00%	20.00%	20.00%	0.00%
93																					
94			Total Rest of State			11.14%	12.14%	13.14%	14.14%	15.14%	16.14%	17.14%	18.14%	19.14%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	0.00%
95																					
96	7	Needed or Known Growth - GWh (total) - if NOT at 20% by 2017 with simple 1 % growth		(Section 6) * (Section 1).																	
97			PG&E			8,828	8,986	9,198	9,755	10,670	11,684	12,629	13,630	14,627	15,634	16,612	16,983	17,257	17,535	17,817	
98			SCE			12,791	13,066	13,483	14,525	15,378	15,709	15,901	16,104	16,347	16,593	16,749	17,038	17,331	17,629	17,932	
99			SDG&E			550	562	750	969	1,198	1,435	1,673	1,914	2,163	2,426	2,678	2,958	3,246	3,544	3,852	
100			Total			22,169	22,614	23,430	25,250	27,246	28,829	30,203	31,648	33,137	34,653	36,040	36,978	37,834	38,708	39,601	
101																					
102			PG&E DA			734	832	933	1,036	1,141	1,248	1,360	1,475	1,592	1,713	1,837	1,961	2,070	2,095	2,120	
103			SCE DA			945	1,075	1,209	1,346	1,486	1,630	1,783	1,940	2,101	2,268	2,439	2,612	2,766	2,807	2,849	
104			SDG&E			271	310	350	392	435	479	527	577	628	682	738	794	845	862	880	
105			Total DA			1,950	2,218	2,492	2,773	3,061	3,357	3,669	3,991	4,322	4,663	5,013	5,367	5,681	5,764	5,849	
106																					
107			Total DA and IOU	19549	19549	24,119	24,831	25,922	28,023	30,307	32,186	33,872	35,639	37,459	39,316	41,054	42,345	43,515	44,472	45,449	
108																					
109			Total Rest of State			8,206	9,063	9,961	10,871	11,793	12,739	13,657	14,619	15,598	16,476	16,642	16,843	17,047	17,254	17,462	
110			Statewide			32,325	33,894	35,883	38,894	42,100	44,925	47,529	50,258	53,057	55,792	57,695	59,189	60,562	61,725	62,911	

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Shading with text is explanatory.
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Appendix A. Estimation of Energy Requirements to meet California's RPS by 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
111	8	Additional Energy (GWh) Per Year on top of Baseline		For 2003, (Section 7) - (Section 2). For other years, (Section 7 current year) - (Section 7 prior year)																	Total Adt'l Ener
112			PG&E			2,109	158	212	558	914	1,015	945	1,001	998	1,007	979	371	274	278	283	11,098
113			SCE			1,427	275	417	1,043	853	331	192	203	243	247	156	288	293	298	303	6,568
114			SDG&E			404	12	188	219	228	238	238	241	249	263	253	279	289	298	307	3,706
115			Total			3,940	445	816	1,820	1,996	1,583	1,374	1,445	1,489	1,516	1,387	938	855	874	893	21,372
116																					
117			MW/Year with 50% CF			900	102	186	415	456	361	314	330	340	346	317	214	195	200	204	4,879
118																					
119			PG&E DA			464	99	101	103	105	107	112	115	118	121	123	124	109	25	25	1,850
120			SCE DA			647	130	133	137	140	144	152	157	162	166	171	173	154	41	42	2,550
121			SDG&E			95	39	40	41	43	44	48	50	52	54	56	56	51	17	17	703
122			Total DA			1,205	268	274	281	288	295	312	322	331	341	351	353	314	83	84	5,104
123																					
124			MW/Year with 50% CF			275	61	63	64	66	67	71	73	76	78	80	81	72	19	19	1,165
125																					
126			Total Rest of State			1,364	857	899	910	922	946	918	962	979	878	166	202	204	206	208	10,620
127																					
128			MW/Year with 50% CF			311	196	205	208	210	216	209	220	224	200	38	46	47	47	48	2,425
129																					
130	9	Cumulative Energy (GWh) Per Year on top of Baseline		For 2003, (Section 8). For other years, (Section 8 current year) + (Section 9 prior year)																	
131			PG&E			2,109	2,266	2,478	3,036	3,950	4,965	5,910	6,910	7,908	8,914	9,893	10,264	10,537	10,815	11,098	
132			SCE			1,427	1,702	2,119	3,162	4,015	4,346	4,537	4,741	4,983	5,230	5,386	5,674	5,967	6,265	6,568	
133			SDG&E			404	416	604	823	1,052	1,290	1,528	1,768	2,017	2,280	2,533	2,812	3,101	3,398	3,706	
134			Total			3,940	4,385	5,201	7,021	9,017	10,600	11,974	13,419	14,908	16,424	17,812	18,750	19,605	20,479	21,372	
135																					
136			Cumulative MW with 50% CF			900	1,001	1,187	1,603	2,059	2,420	2,734	3,064	3,404	3,750	4,067	4,281	4,476	4,676	4,879	
137																					
138			PG&E DA			464	563	663	766	871	978	1,090	1,205	1,323	1,443	1,567	1,691	1,800	1,825	1,850	
139			SCE DA			647	777	910	1,047	1,187	1,331	1,484	1,641	1,802	1,969	2,140	2,313	2,467	2,508	2,550	
140			SDG&E			95	134	174	215	258	302	350	400	452	505	561	618	669	686	703	
141			Total DA			1,205	1,473	1,747	2,028	2,316	2,612	2,924	3,246	3,577	3,918	4,268	4,622	4,936	5,019	5,104	
142																					
143			Cumulative MW with 50% CF			275	336	399	463	529	596	668	741	817	894	975	1,055	1,127	1,146	1,165	
144																					
145			Total Rest of State			1,364	2,221	3,119	4,029	4,951	5,897	6,815	7,777	8,756	9,634	9,800	10,002	10,205	10,412	10,620	
146																					
147			Cumulative MW with 50% CF			311	507	712	920	1,130	1,346	1,556	1,776	1,999	2,200	2,237	2,283	2,330	2,377	2,425	
148																					
149	10	Cumulative Energy (GWh) Per Year on top of Baseline AFTER 2003		For 2003, zero. For 2004, (Section 8). For other years, (Section 8 current year) + (Section 10 prior year)																	
150			PG&E				158	370	927	1,842	2,856	3,801	4,802	5,799	6,806	7,784	8,155	8,429	8,707	8,989	
151			SCE				275	692	1,735	2,587	2,918	3,110	3,313	3,556	3,802	3,959	4,247	4,540	4,838	5,141	
152			SDG&E				12	200	419	648	885	1,123	1,364	1,613	1,876	2,128	2,408	2,696	2,994	3,302	
153			Total				445	1,261	3,081	5,077	6,660	8,034	9,479	10,968	12,484	13,871	14,810	15,665	16,539	17,432	
154																					
155			Cumulative MW with 50% CF				102	288	703	1,159	1,521	1,834	2,164	2,504	2,850	3,167	3,381	3,576	3,776	3,980	
156																					
157			PG&E DA				99	199	302	407	514	626	741	859	979	1,103	1,227	1,336	1,361	1,386	
158			SCE DA				130	264	400	541	685	837	994	1,156	1,322	1,494	1,667	1,820	1,862	1,904	
159			SDG&E				39	79	120	163	208	255	305	357	411	466	523	574	591	609	
160			Total DA				268	542	823	1,111	1,406	1,719	2,041	2,372	2,712	3,063	3,416	3,731	3,814	3,898	
161																					
162			Cumulative MW with 50% CF				61	124	188	254	321	392	466	541	619	699	780	852	871	890	
163																					
164			Total Rest of State				857	1,755	2,665	3,587	4,533	5,451	6,413	7,392	8,270	8,436	8,637	8,841	9,047	9,256	
165																					
166			Cumulative MW with 50% CF				196	401	609	819	1,035	1,244	1,464	1,688	1,888	1,926	1,972	2,019	2,066	2,113	
167																					
168						DA and IOU	712	1,803	3,904	6,188	8,066	9,753	11,520	13,340	15,197	16,935	18,226	19,395	20,353	21,330	
169						Whole State	1,569	3,558	6,569	9,775	12,600	15,204	17,932	20,732	23,467	25,370	26,863	28,237	29,400	30,586	

2004 20-2017

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Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1			Staff's Outlook for California - Retails Sales by Utility (GWh). Updated June 2004. Lynn Marshall. Energy Commission's Demand Analysis office through 2013. Staff projected out to 2017 based on (1a)																		
2				**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	
3	**1**	Sales (GWh)	**PG&E**	75,681	70,861	71,224	72,496	74,205	75,748	76,879	78,530	79,535	80,751	81,814	82,812	83,569	84,915	86,283	87,674	89,086	**1.61%**
4			**SCE**	74,286	68,427	70,617	72,136	73,687	75,272	76,892	78,546	79,504	80,520	81,734	82,967	83,747	85,188	86,653	88,144	89,660	**1.72%**
5			**SDG&E**	15,000	14,301	15,040	15,363	15,693	16,029	16,373	16,724	16,985	17,213	17,461	17,763	17,945	18,264	18,590	18,921	19,258	**1.78%**
6			**Total**	164,967	153,589	156,881	159,995	163,585	167,049	170,143	173,800	176,024	178,484	181,008	183,541	185,261	188,368	191,526	194,738	198,004	
7																					
8		Grand Total Statewide Sales		242,861	246,910	254,442	258,858	263,924	268,784	273,213	278,238	281,616	285,399	289,250	293,077	296,061	300,580	305,169	309,827	314,556	1.53%
9		DA and Rest		77,895	93,322	97,562	98,864	100,338	101,734	103,070	104,438	105,591	106,915	108,241	109,536	110,800	112,213	113,642	115,089	116,552	1.28%
10			**PG&E DA**	3,761	7,433	8,979	9,076	9,173	9,272	9,372	9,473	9,597	9,722	9,848	9,977	10,108	10,228	10,350	10,473	10,598	1.19%
11			**SCE DA**	4,168	11,234	11,571	11,728	11,887	12,048	12,212	12,377	12,580	12,785	12,995	13,207	13,424	13,625	13,829	14,036	14,246	1.50%
12			**SDG&E DA**	2,463	3,448	3,322	3,383	3,445	3,508	3,572	3,637	3,718	3,801	3,885	3,972	4,060	4,143	4,227	4,312	4,400	2.03%
13			**Total DA**	10,392	22,115	23,871	24,186	24,505	24,828	25,156	25,488	25,894	26,308	26,728	27,156	27,592	27,995	28,405	28,821	29,243	1.46%
14			**Total Rest of State**	67,503	71,207	73,690	74,678	75,833	76,906	77,914	78,950	79,697	80,608	81,513	82,380	83,209	84,217	85,237	86,268	87,309	1.22%
15			**DA % of Diff**	13.34%	23.70%	24.47%	24.46%	24.42%	24.40%	24.41%	24.40%	24.52%	24.61%	24.69%	24.79%	24.90%	24.95%	25.00%	25.04%	25.09%	
16			**Rest of State % of Diff**	86.66%	76.30%	75.53%	75.54%	75.58%	75.60%	75.59%	75.60%	75.48%	75.39%	75.31%	75.21%	75.10%	75.05%	75.00%	74.96%	74.91%	
17																					
18		Percent IOU sales		67.93%	62.20%	61.66%	61.81%	61.98%	62.15%	62.27%	62.46%	62.51%	62.54%	62.58%	62.63%	62.58%	62.67%	62.76%	62.85%	62.95%	
19		Percent DA		4.28%	8.96%	9.38%	9.34%	9.28%	9.24%	9.21%	9.16%	9.19%	9.22%	9.24%	9.27%	9.32%	9.31%	9.31%	9.30%	9.30%	
20		Percent Rest		27.79%	28.84%	28.96%	28.85%	28.73%	28.61%	28.52%	28.37%	28.30%	28.24%	28.18%	28.11%	28.11%	28.02%	27.93%	27.84%	27.76%	
21																					
22	**2**	**2001 Baseline**	THIS IS CHANGEABLE	2001 GWh	2001%		2002 GWh	2002%	2003 GWh	2003%											
23			**PG&E**	6,719	8.88%		7,392	10.43%	8,828	12.39%		This is for a 7 year total (accounts for 2003 Interim Procurement)									
24			**SCE**	11,364	15.30%		12,018	17.56%	12,791	18.11%		**20% Goal**	**Minus Bas**	**Avg. GWh Yr.**	**MW/Year**						
25			**SDG&E**	146	0.97%		141	0.99%	550	3.66%		Take 20%	Base and 2	Divide by 7	MW with 5(	55% CF					
26			**Total**	18,229	11.05%							5,262	5,262	752	**172**	**156**	**DA no baseline**				
27												5,262	3,311	473	**108**	**98**	**DA w/ baseline**				
28		7.17%	**PG&E DA**	270	7.17%																
29			**SCE DA**	299	7.17%							16,122	7,915	1,131	**258**	**235**	**Rest of State**				
30			**SDG&E**	177	7.17%							35,697	13,198	1,885	**430**	**391**	**IOUs**				
31			**Total DA**	745	7.17%																
32																					
33			**Total DA and IOU Baseline**	18,974																	
34																					
35			**Total Rest of State**	6,842	10.14%							This is for a 8 year total (only baseline)									
36												**20% Goal**	**Minus Bas**	**Avg. GWh Yr.**	**MW/Year**						
37			**J-11 Figure**	25,816								Take 20%	Base only	Divide by 8	MW with 5(	55% CF					
38												5,262	5,262	658	**150**	**137**	**DA no baseline**				
39												5,262	4,516	565	**129**	**117**	**DA w/ baseline**				
40																					
41												16,122	9,280	1,160	**265**	**241**	**Rest of State**				
42												35,697	17,468	2,184	**499**	**453**	**IOUs**				
43																					
44	**3**	**1% Minimum Percentage Point Growth (capped) as percent**		[% shown in (Section 2)] + [1%] up to [20%].																	
45			**PG&E**			9.88%	10.88%	11.88%	12.88%	13.88%	14.88%	15.88%	16.88%								
46			**SCE**			16.30%	17.30%	18.30%	19.30%	20.00%	20.00%	20.00%	20.00%								
47			**SDG&E**			1.97%	2.97%	3.97%	4.97%	5.97%	6.97%	7.97%	8.97%								
48			**Total**																		
49																					
50			**PG&E DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
51			**SCE DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
52			**SDG&E DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
53			**Total DA**			8.17%	9.17%	10.17%	11.17%	12.17%	13.17%	14.17%	15.17%								
54																					
55			**Total Rest of State**			11.14%	12.14%	13.14%	14.14%	15.14%	16.14%	17.14%	18.14%								
56																					

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Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
57	4	1% Minimum Percentage Point Growth (capped) as GWh		(Section 3) * (Section 1).																	
58			PG&E			7,036	7,887	8,815	9,755	10,670	11,684	12,629	13,630								
59			SCE			11,508	12,477	13,483	14,525	15,378	15,709	15,901	16,104								
60			SDG&E			297	457	623	797	978	1,166	1,354	1,544								
61			Total			18,841	20,821	22,921	25,078	27,026	28,559	29,884	31,278								
62																					
63			PG&E DA			734	832	933	1,036	1,141	1,248	1,360	1,475								
64			SCE DA			945	1,075	1,209	1,346	1,486	1,630	1,783	1,940								
65			SDG&E DA			271	310	350	392	435	479	527	577								
66			Total DA			1,950	2,218	2,492	2,773	3,061	3,357	3,669	3,991								
67																					
68			Total Rest of State			8,206	9,063	9,961	10,871	11,793	12,739	13,657	14,619								
69																					
70	5	Additional Energy (GWh) Per Year on top of Baseline		For 2003, (Section 4) - (Section 2). For other years, (Section 4 current year) - (Section 4 prior year)																	
71			PG&E			317	851	928	941	914	1,015	945	1,001								
72			SCE			145	969	1,005	1,043	853	331	192	203								
73			SDG&E			151	160	167	174	181	188	188	190								
74			Total			612	1,980	2,100	2,157	1,948	1,534	1,325	1,394								
75																					
76			PG&E DA			464	99	101	103	105	107	112	115								
77			SCE DA			647	130	133	137	140	144	152	157								
78			SDG&E DA			95	39	40	41	43	44	48	50								
79			Total DA			1,205	268	274	281	288	295	312	322								
80																					
81			Total Rest of State			1,364	857	899	910	922	946	918	962								
82																					
83	6	Needed or Known Growth - percent (total) - if NOT at 20% by 2017 with simple 1 % growth		Shaded highlights represent known Procurements. Otherwise, if not at 20% by (Section 3) method, grow at annual average percent to reach 20% by 2017. If percentage drops over time, this is because the IOU procured more in one year than they were required to, so they are "banking" it forward. The percentage will increase once procurements start again.										Annual Avg. Growth Rate if not at 20% by 2010 at 1%							
84			PG&E			12.39%	12.39%	13.05%	14.44%	15.83%	17.22%	18.61%	20.00%	1.39%							
85			SCE			18.11%	18.11%	18.30%	19.30%	20.00%	20.00%	20.00%	20.00%	0.00%							
86			SDG&E			3.66%	5.73%	8.11%	10.49%	12.86%	15.24%	17.62%	20.00%	2.38%							
87			Total			14.13%	14.33%	14.94%	16.25%	17.43%	18.29%	19.14%	20.00%								
88																					
89			PG&E DA			8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
90			SCE DA			8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
91			SDG&E DA			8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
92			Total			8.17%	10.38%	11.98%	13.59%	15.19%	16.79%	18.40%	20.00%	1.60%							
93																					
94			Total Rest of State			11.14%	12.60%	13.83%	15.07%	16.30%	17.53%	18.77%	20.00%	1.23%							
95																					
96	7	Needed or Known Growth - GWh (total) - if NOT at 20% by 2017 with simple 1 % growth		(Section 6) * (Section 1).																	
97			PG&E	-		8,828	8,986	9,683	10,937	12,170	13,523	14,801	16,150	16,363	16,562	16,714	16,983	17,257	17,535	17,817	
98			SCE	-		12,791	13,066	13,483	14,525	15,378	15,709	15,901	16,104	16,347	16,593	16,749	17,038	17,331	17,629	17,932	
99			SDG&E	-		550	880	1,272	1,681	2,106	2,549	2,993	3,443	3,492	3,553	3,589	3,653	3,718	3,784	3,852	
100			Total	-		22,169	22,932	24,438	27,144	29,654	31,781	33,695	35,697	36,202	36,708	37,052	37,674	38,305	38,948	39,601	
101																					
102			PG&E DA	-		734	942	1,099	1,260	1,424	1,591	1,765	1,944	1,970	1,995	2,022	2,046	2,070	2,095	2,120	
103			SCE DA	-		945	1,217	1,424	1,637	1,855	2,078	2,314	2,557	2,599	2,641	2,685	2,725	2,766	2,807	2,849	
104			SDG&E DA	-		271	351	413	477	543	611	684	760	777	794	812	829	845	862	880	
105			Total DA	-		1,950	2,510	2,936	3,373	3,821	4,280	4,764	5,262	5,346	5,431	5,518	5,599	5,681	5,764	5,849	
106																					
107			Total DA and IOU	18,974	18,974	24,119	25,442	27,374	30,517	33,475	36,061	38,459	40,958	41,547	42,139	42,571	43,273	43,986	44,712	45,449	
108																					
109			Total Rest of State	-		8,206	9,411	10,491	11,588	12,701	13,843	14,957	16,122	16,303	16,476	16,642	16,843	17,047	17,254	17,462	
110			Statewide			32,325	34,853	37,866	42,105	46,176	49,904	53,416	57,080	57,850	58,615	59,212	60,116	61,034	61,965	62,911	

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Shading with text is explanatory.
Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

Appendix A (2). Estimation of Energy Requirements to meet California's RPS by 2010

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
2				2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	
111	8	**Additional Energy (GWh) Per Year on top of Baseline**		For 2003, (Section 7) - (Section 2). For other years, (Section 7 current year) - (Section 7 prior year)																	
112			**PG&E**			2,109	158	697	1,254	1,232	1,353	1,279	1,349	213	200	151	269	274	278	283	
113			**SCE**			1,427	275	417	1,043	853	331	192	203	243	247	156	288	293	298	303	
114			**SDG&E**			404	330	392	409	425	443	444	450	49	60	36	64	65	66	67	
115			**Total**		-	3,940	763	1,506	2,706	2,510	2,127	1,914	2,002	505	507	344	621	632	642	653	
116																					
117			**Cumulative MW with 50% CF**			900	174	344	618	573	486	437	457	115	116	79	142	144	147	149	3,089
118																					
119			**PG&E DA**			464	208	157	161	164	167	175	179	25	26	26	24	24	25	25	
120			**SCE DA**			647	272	207	213	218	224	236	243	42	43	43	40	41	41	42	
121			**SDG&E DA**			95	80	62	64	66	68	73	76	17	17	18	16	17	17	17	
122			**Total DA**			1,205	560	426	437	448	459	483	498	84	86	87	81	82	83	84	
123																					
124			**Cumulative MW with 50% CF**			275	128	97	100	102	105	110	114	19	20	20	18	19	19	19	756
125																					
126			**Total Rest of State**	-		1,364	1,205	1,081	1,097	1,113	1,142	1,114	1,165	181	173	166	202	204	206	208	
127																					
128			**Cumulative MW with 50% CF**			311	275	247	250	254	261	254	266	41	40	38	46	47	47	48	1,807
129			**DA and IOU**			5,145	1,323	1,932	3,142	2,958	2,586	2,398	2,500	589	592	431	702	714	726	738	
130	9	**Cumulative Energy (GWh) Per Year on top of Baseline**		For 2003, (Section 8). For other years, (Section 8 current year) + (Section 9 prior year)																706.47	5,652
131			**PG&E**			2,109	2,266	2,964	4,218	5,450	6,803	8,082	9,431	9,643	9,843	9,994	10,264	10,537	10,815	11,098	
132			**SCE**			1,427	1,702	2,119	3,162	4,015	4,346	4,537	4,741	4,983	5,230	5,386	5,674	5,967	6,265	6,568	
133			**SDG&E**			404	734	1,126	1,535	1,961	2,403	2,847	3,297	3,346	3,407	3,443	3,507	3,572	3,638	3,706	
134			**Total**			3,940	4,703	6,209	8,915	11,425	13,552	15,466	17,468	17,973	18,479	18,823	19,445	20,077	20,719	21,372	
135																					
136			**Cumulative MW with 50% CF**			900	1,074	1,418	2,035	2,609	3,094	3,531	3,988	4,103	4,219	4,298	4,439	4,584	4,730	4,879	
137																					
138			**PG&E DA**			464	672	829	990	1,154	1,321	1,496	1,675	1,700	1,726	1,752	1,776	1,800	1,825	1,850	
139			**SCE DA**			647	918	1,125	1,338	1,556	1,780	2,015	2,258	2,300	2,343	2,386	2,426	2,467	2,508	2,550	
140			**SDG&E DA**			95	174	236	300	366	434	507	584	600	618	635	652	669	686	703	
141			**Total DA**			1,205	1,765	2,191	2,628	3,076	3,535	4,018	4,516	4,601	4,686	4,773	4,854	4,936	5,019	5,104	
142																					
143			**Cumulative MW with 50% CF**			275	403	500	600	702	807	917	1,031	1,050	1,070	1,090	1,108	1,127	1,146	1,165	
144																					
145			**Total Rest of State**			1,364	2,569	3,649	4,746	5,859	7,001	8,115	9,280	9,461	9,634	9,800	10,002	10,205	10,412	10,620	
146																					
147			**Cumulative MW with 50% CF**			311	586	833	1,084	1,338	1,598	1,853	2,119	2,160	2,200	2,237	2,283	2,330	2,377	2,425	
148																					
149	10	**Cumulative Energy (GWh) Per Year on top of Baseline AFTER 2003 and 2004 KNOWN PROCUREMENTS**		For 2003, zero. For 2004, (Section 8). For other years, (Section 8 current year) + (Section 10 prior year)																	
150			**PG&E**				158	855	2,109	3,341	4,695	5,973	7,322	7,535	7,734	7,886	8,155	8,429	8,707	8,989	
151			**SCE**				275	692	1,735	2,587	2,918	3,110	3,313	3,556	3,802	3,959	4,247	4,540	4,838	5,141	
152			**SDG&E**				330	722	1,131	1,556	1,999	2,443	2,893	2,942	3,003	3,039	3,103	3,168	3,234	3,302	
153			**Total**				763	2,269	4,975	7,485	9,612	11,526	13,528	14,033	14,539	14,883	15,505	16,136	16,779	17,432	
154																					
155			**Cumulative MW with 50% CF**				174	518	1,136	1,709	2,195	2,632	3,089	3,204	3,319	3,398	3,540	3,684	3,831	3,980	
156																					
157			**PG&E DA**				208	366	526	690	857	1,032	1,211	1,236	1,262	1,288	1,312	1,336	1,361	1,386	
158			**SCE DA**				272	479	691	909	1,133	1,369	1,612	1,654	1,696	1,739	1,780	1,820	1,862	1,904	
159			**SDG&E DA**				80	141	205	271	339	413	489	506	523	541	557	574	591	609	
160			**Total**				560	986	1,423	1,871	2,330	2,813	3,311	3,395	3,481	3,568	3,649	3,731	3,814	3,898	
161																					
162			**Cumulative MW with 50% CF**				128	225	325	427	532	642	756	775	795	815	833	852	871	890	
163																					
164			**Total Rest of State**				1,205	2,285	3,382	4,495	5,637	6,751	7,915	8,097	8,270	8,436	8,637	8,841	9,047	9,256	
165																					
166			**Cumulative MW with 50% CF**				275	522	772	1,026	1,287	1,541	1,807	1,849	1,888	1,926	1,972	2,019	2,066	2,113	
167																					
168						DA and IOI	1,323	3,255	6,397	9,356	11,942	14,340	16,839	17,428	18,020	18,451	19,153	19,867	20,593	21,330	
169						Whole Stat	2,527	5,540	9,780	13,851	17,579	21,090	24,755	25,525	26,290	26,887	27,791	28,709	29,640	30,586	
170																					

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Shading with text is explanatory.
Shading with numbers or percentages are from CPUC fillings or press releases regarding the 2001 Baseline or 2002 and 2003 renewable procurements.

Staff 2003-2013 Demand Forecast - Updated June 2004
Retail Sales by Utility (GWh)

Year	PG&E: PG&E Customers	PG&E: Municipal Sales in PG&E	PG&E: Direct Access Sales in PG&E	Total PG&E	SMUD	SCE: SCE Customers	SCE: Sales in SCE	SCE: Direct Access Sales in SCE	Total SCE	LADWP	SDG&E: SDG&E Customers	SDG&E: Sales in SDG&E		BGP	OTH	DWR	TOTAL	
1980	54,908	10,658	0	65,566	5,350	53,465	5,870	0		17,669	9,729	0		2,374	2,677	3,354	166,056	
1981	56,023	10,993	0	67,016	5,693	55,182	6,116	0		18,340	9,875	0		2,452	2,781	5,264	172,719	
1982	54,767	10,548	0	65,315	5,681	53,313	5,696	0		18,184	9,812	0		2,399	2,660	5,192	168,252	4.01%
1983	56,757	10,792	0	67,549	5,954	55,170	5,922	0		18,492	10,023	0		2,433	2,595	2,497	170,636	-2.59%
1984	60,616	11,851	0	72,467	6,360	58,745	6,761	0		19,438	10,616	0		2,644	2,722	3,349	183,102	1.42%
1985	62,395	12,198	0	74,593	6,881	60,034	6,883	0		19,443	10,930	0		2,699	2,770	5,410	189,643	7.31%
1986	61,071	11,637	0	72,708	7,014	61,125	6,943	0		19,671	11,363	0		2,695	2,758	5,031	189,308	3.57%
1987	63,903	12,317	0	76,220	7,419	63,962	7,247	0		20,284	11,920	0		2,754	2,872	4,734	197,412	-0.18%
1988	66,006	12,733	0	78,739	7,677	66,251	7,428	0		20,719	12,713	0		2,861	3,055	5,928	205,371	4.28%
1989	67,642	13,045	0	80,687	7,927	67,914	7,305	0		20,642	13,427	0		2,813	3,205	7,413	211,331	4.03%
1990	69,445	13,369	0	82,814	8,358	70,464	7,901	0		20,953	14,331	0		2,951	3,310	8,171	219,254	2.90%
1991	69,571	13,214	0	82,785	8,349	69,072	7,787	0		20,457	14,171	0		2,759	3,323	4,400	213,103	3.75%
1992	70,671	13,467	0	84,138	8,496	71,087	7,545	0		20,945	15,093	0		2,931	3,513	4,088	217,837	-2.81%
1993	70,654	13,382	0	84,036	8,435	69,791	7,654	0		21,259	15,036	0		2,996	3,602	4,372	217,180	2.22%
1994	70,733	13,350	0	84,084	8,418	71,117	7,952	0		20,308	15,381	0		2,999	3,758	4,946	218,962	-0.30%
1995	71,797	13,467	0	85,264	8,458	71,548	7,577	0		20,939	15,524	0		3,084	3,819	3,562	219,774	0.82%
1996	73,273	13,746	0	87,019	8,805	73,766	8,029	0		21,228	16,046	0		3,152	3,983	5,146	227,174	0.37%
1997	76,241	14,327	0	90,568	9,006	76,057	8,300	0		21,605	16,748	0		3,236	3,972	5,504	234,995	3.37%
1998	70,121	14,364	5,559	90,044	9,123	70,097	8,189	6,161		21,412	13,609	3,641		3,298	3,911	3,421	232,905	3.44%
1999	71,251	14,564	7,958	93,773	9,326	69,388	8,782	8,819		21,434	12,719	5,211		3,240	4,009	5,490	242,192	-0.89%
2000	73,387	15,039	8,396	96,822	9,491	74,130	9,108	9,304		22,146	12,926	5,498		3,320	4,227	5,490	252,464	3.99%
2001	75,681	14,110	3,761	93,551	9,334	74,286	8,631	4,168	87,084	21,575	15,000	2,463	17,463	3,275	4,230	6,349	242,861	4.24%
2002	70,861	15,085	7,433	93,379	9,475	68,427	8,593	11,234	88,255	22,507	14,301	3,448	17,748	3,248	4,409	7,889	246,910	-3.80%
2003	71,224	16,232	8,979	96,434	9,922	70,617	8,742	11,571	90,930	23,137	15,040	3,322	18,362	3,345	4,423	7,889	254,442	1.67%
2004	72,496	16,526	9,076	98,097	10,084	72,136	8,896	11,728	92,759	23,393	15,363	3,383	18,746	3,375	4,514	7,889	258,858	3.05%
2005	74,205	16,825	9,173	100,204	10,248	73,687	9,140	11,887	94,715	23,653	15,693	3,445	19,137	3,471	4,607	7,889	263,924	1.74%
2006	75,748	17,130	9,272	102,150	10,415	75,272	9,352	12,048	96,673	23,916	16,029	3,508	19,537	3,504	4,701	7,889	268,784	1.96%
2007	76,879	17,440	9,372	103,691	10,584	76,892	9,506	12,212	98,610	24,181	16,373	3,572	19,945	3,516	4,798	7,889	273,213	1.84%
2008	78,530	17,756	9,473	105,759	10,756	78,546	9,673	12,377	100,596	24,449	16,724	3,637	20,362	3,530	4,896	7,889	278,238	1.65%
2009	79,535	17,957	9,597	107,089	10,923	79,504	9,816	12,580	101,899	24,583	16,985	3,718	20,704	3,542	4,986	7,889	281,616	1.84%
2010	80,751	18,199	9,722	108,671	11,090	80,520	9,963	12,785	103,269	24,769	17,213	3,801	21,014	3,555	5,143	7,889	285,399	1.21%
2011	81,814	18,417	9,848	110,080	11,255	81,734	10,124	12,995	104,852	24,990	17,461	3,885	21,346	3,570	5,268	7,889	289,250	1.34%
2012	82,812	18,619	9,977	111,408	11,413	82,967	10,287	13,207	106,461	25,159	17,763	3,972	21,734	3,582	5,430	7,889	293,077	1.35%
2013	83,569	18,763	10,108	112,440	11,568	83,747	10,402	13,424	107,573	25,401	17,945	4,060	22,005	3,592	5,593	7,889	296,061	1.32%
	0.00%	14.49%	6.76%	2.76%	3.55%	5.62%	0.00%	2.96%	4.72%	5.33%	2.30%	-4.72%	#DIV/0!	0.00%	3.29%	0.00%	3.47%	1.02%
Annual Growth Rates (%)																		
1980-1990	2.4	2.3		2.4	4.6	2.8	3.0			1.7	3.9			2.2	2.1	9.3	2.8	
1990-2000	0.6	1.2		1.6	1.3	0.5	1.4			0.6	-1.0			1.2	2.5	-3.9	1.4	
2000-2001	3.1	-6.2	-55.2	-3.4	-1.7	0.2	-5.2	-55.2		-2.6	16.0	-55.2		-1.4	0.1	15.6	-3.8	
2003-2008	2.0	1.8	1.1	1.9	1.6	2.2	2.0	1.4		1.1	2.1	1.8		1.1	2.1	0.0	1.8	
2008-2013	1.3	1.1	1.3	1.2	1.5	1.3	1.5	1.6		0.8	1.4	2.2		0.4	2.7	0.0	1.2	
2003-2013	1.611299	1.460057	1.191242	1.547441	1.546150	1.720041	1.753194	1.496420		0.938168	1.781207	2.028233		0.715393	2.374453	0.000000	1.526458	

Historic data through 2003

Retail Sales = Consumption minus private supply (self-gen, over the fence)

Appendix A: Notes

Notes regarding the preparation of staff estimate of California retail sales:

The retail sales forecast is derived from the final electricity demand forecast developed for the Integrated Energy Policy Report (IEPR) that is currently under preparation. Staff forecasts electricity demand using models developed at the Energy Commission, with the exception of the industrial and mining sectors, for which the staff uses the INFORM model originally developed by the Electric Power Research Institute (EPRI). Each model develops a forecast using a complex series of calculations that simultaneously consider economic and demographic trends, weather characteristics, changes in energy utilization, regulatory conditions, and recorded consumption. Population and personal income are key drivers for the residential and commercial sectors. Employment and shipments are drivers for the commercial and industrial sectors.

Staff develops a forecast of households using the California Department of Finance population projections. Projections of personal income, shipments and employment are developed from the University of California at Los Angeles (UCLA) Anderson School of Business California forecast of September 2002. This forecast assumes that stronger economic growth will resume in late 2003, followed by steady growth, but at a lower rate than previous post-recession periods. A more detailed presentation of this forecast and assumptions will be published in a Technical Appendix to the IEPR. Descriptions of forecasting methods are also contained in “California Energy Demand: 1995-2015, Volume II Electricity Demand Forecasting Models”, July 1995, Publication Number P300-95-005.

The final demand forecast for the IEPR incorporate several changes as a result of comments received on the draft forecast presented at the February 26, 2003 IEPR workshop. Staff revised the electricity rate forecasts based on comments from utilities. Staff also updated the IOU’s present rates to reflect recent changes. Demand reductions from energy efficiency programs included in the forecast are now consistent with the assumption that the current level of program funding persists through 2011, as authorized by the legislature. In addition, staff modified the residential demand model to better estimate the effect of growth in personal income on residential consumption. The combined effect of these changes is to reduce average annual demand growth by 0.5 percent per year over the next ten years. The average growth rate of the final statewide electricity consumption forecast is 1.6% per year over the next ten years.

Appendix A: Notes

The Commission's energy demand models produce forecasts of electricity consumption for eight utility planning areas. To develop a forecast of utility customer sales for Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), three adjustments are made to the planning area forecast. First, electricity consumption needs that are privately supplied through self-generation or distributed generation are excluded. To forecast private supply, staff estimated peak load and consumption for 2002 and 2003 using data from PG&E, SCE and SDG&E on new interconnect activity in their territories. After 2003, privately supplied load is assumed to grow at one percent per year.

Second, staff used historic consumption data to allocate the planning area forecast between the utilities' own customers, and water districts and municipalities (or resale cities) in that planning area.

Third, sales to direct access customers are subtracted from the utility customer forecast. To forecast direct access sales, staff used 2002 CPUC reports on actual direct access sales, and assumed that direct access demand grows at the same rate as the overall customer sector for that utility.

Appendix B. Renewables Portfolio Standard Procurement Process for Investor-owned Utilities

This appendix describes how the IOUs are conducting competitive bid solicitations in California's RPS program. The following topics are discussed:

- Annual Procurement Targets (APTs)
- IOU Request for Offers to meet RPS obligations
- Market Price Referent
- Bid Evaluation – IOU Selection of Least-Cost-Best-Fit Bids
- Integration Costs
- Transmission Costs
- Other Considerations in Bid Evaluation
- Disclosure of Market Price Referents
- Bids above the Market Price Referent – Supplemental Energy Payments
- Applying for Certification and Pre-Certification
- Eligibility for Supplemental Energy Payments
- Rules that apply when a bidder has an SB 90 Award
- Multiple Awards
- Tracking Progress

Please note that the CPUC and Energy Commission are working collaboratively to implement the RPS. Although the summary below identifies which agency is the lead decision maker for various topics, the two agencies work in close consultation as directed by law.

Annual Procurement Targets

The annual amount of eligible renewable resources the IOUs must procure is set by the CPUC and is termed the "annual procurement target." The annual procurement target is the amount of eligible renewable energy each IOU must procure to increase its procurement of renewable resources by at least 1 percent of retail sales per year. The annual procurement target is comprised of two components combined:

1. The baseline which represents the IOUs procurement in year 2001 and is adjusted to include renewable procurement in subsequent years.

2. The incremental procurement target, defined as at least 1 percent of the previous year's total retail electrical sales, including power sold to a utility's customers from its Department of Water Resources contracts.[1]

If the IOU's baseline declines, the IOU must compensate by procuring additional renewable energy to cover the reduction in order to meet its annual procurement target. The baseline may decline, for example, if an IOU's contract that was in place in 2001 with a renewable facility expires and is not renewed. Continuing the example, if the contract was for 50 MWh/year, then the IOU needs to procure an additional 50 MWh/year (increasing its incremental procurement target by 50 MWh/year) to achieve its entire annual procurement target.[2]

For 2004, the CPUC identified RPS procurement targets for each utility based on 2003 retail sales. The baseline for each utility reflects its 2001 procurement of renewable energy, updated to account for subsequent procurement of renewables in 2002 and 2003. The targets are shown in Table 10.

Table 10. Annual Procurement Targets for 2004 RPS Procurement

	Renewable Generation (kWh) for 2017 Target[3]
SDG&E	423,336,191 kWh
SCE[4]	12,736,041,629 kWh
PG&E	9,474,758,630 kWh

Source: California Public Utilities Commission, D. 04-06-014

It should be noted, however, that although the annual procurement target is not optional, the IOUs have some compliance flexibility. As described in the CPUC's Decision 03-06-071, a utility can procure in excess of its annual procurement target and count the excess towards future year requirements. Conversely, an IOU is required to meet 75 percent of its annual procurement target each year and may carry a deficit of 25 percent for up to three years. The CPUC may permit an IOU to procure less than 75 percent of its annual procurement target if the IOU demonstrates one of the following conditions:

- Insufficient response to its solicitation for bids
- Contracts already in place will provide sufficient deliveries to satisfy deficits in future years
- Public goods charge funds are inadequate to cover the above market costs of bids
- Seller has not performed due to factors beyond the utility's control, such as contract default, force majeure, terminations or project development delays

With this flexibility, if a utility is still in non-compliance with meeting its annual procurement target, it faces a penalty of five cents per kWh, with an overall annual penalty cap per utility of $25 million (D.03-06-071). The CPUC would administer any such penalties.

IOU Request for Offers to Meet RPS Obligations

To meet their APT, the IOUs hold competitive solicitations requesting bids for electricity delivered from existing or planned renewable projects eligible for the RPS. The IOUs are also allowed to procure RPS-eligible electricity through bilateral contracts, but bilateral contracts are not eligible for RPS financial incentives from the Energy Commission.

The IOUs held a competitive solicitation in 2002 under CPUC direction consistent the SB 1078. The solicitation was termed “interim,” however, because the RPS implementation rules and guidelines were not yet in place. In July 2004, the IOUs initiated the first formal RPS solicitation subject to the RPS implementation procedures adopted by the CPUC and the Energy Commission.

Prior to holding an RPS solicitation, an IOU must receive approval from the CPUC for how they plan to conduct their solicitation. Each IOU submits a “renewable procurement plan” to the CPUC. The plan describes how the IOU will meet its annual procurement target. If an IOU anticipates holding a solicitation for the present year, the plan includes the IOU’s draft Request for Offers to conduct a solicitation to procure renewables. The Request for Offers must reflect the standard contract terms and conditions specified by the CPUC (described below), and the IOU’s preferences for deliverability, on-line dates, and location. Once approved by the CPUC, the IOU must issue the Request for Offers, consistent with its approved plan (D.04-06-014).

The IOU’s Request for Offers must include specific contract terms and conditions that have been adopted by the CPUC (D. 04-06-014) including:

- The definition of RECs and the requirement that the renewable seller transfer REC ownership to the IOU.
- Contingencies for the possibility that a contract qualifies for supplemental energy payments from the Energy Commission, but does not receive the full incentive that would support the bid price proposed. This might happen if the Energy Commission does not award the full amount requested, or if the Energy Commission revokes the award.
- Set delivery terms of 10, 15, and 20 years, and the allowance to apply for CPUC approval of a non-standard delivery term.
- The requirement that facilities must be certified by the Energy Commission as eligible for the RPS.
- Provisions for confidentiality, which parties may modify to allow for more information to be made public.

The CPUC also adopted standard language that the parties may modify if agreed upon in writing by both parties:

- Renewable electricity product definitions, including “as-available” and “unit firm.” As-available products refer to intermittent resources such as wind power or solar-thermal electric generation. Unit firm products include “peaking,” “baseload,” and “dispatchable.”

- Default provisions such as failure to make payment, bankruptcy, or false representation.
- Compliance with prevailing wage requirements.

Bidders may submit bids for the same product in more than one IOU’s RPS solicitation. If a bidder is notified that it has been selected for inclusion on an IOU’s “short list” of bids under consideration for contract, the bidder has five business days to withdraw any conflicting bids prior to commencement of negotiations with the IOU. If the bidder refuses, the IOU is allowed to end negotiations.

Market Price Referent

The MPR establishes a benchmark such that winning bids priced below or equal to the MPR will be considered *per se* reasonable to the CPUC (on a net-present value basis). Bids that exceed the MPR may be eligible for SEPs for up to the difference between the bid price and the MPR.

At least initially, the CPUC will calculate two sets of MPRs, one for baseload products and one for peaking generation. For each product type, the CPUC will set MPRs for 10, 15, and 20 year contracts, for a total of six MPRs.[5]

Each MPR will reflect the levelized price at which the revenues from a proxy power plant equal the expected costs, on a net present value basis. The MPR includes fixed and variable costs added together into one levelized “all-in” price.

The fixed costs include insurance, property and income taxes, fixed operation and maintenance costs, debt cost (the cost of paying off the loan for construction), and the cost of rate of return on the down payment. The CPUC will estimate total revenues for the fixed component of the MPR by multiplying the annual proxy plant electricity production (e.g. 10 million KWh) by the fixed cost component of the MPR (e.g. 1.0 cent per kWh).

Following the approach for the fixed costs, the variable component of the MPR will reflect the expected revenues needed to match the variable costs of the proxy plant. The variable costs include variable operation and maintenance costs, and the cost of natural gas consumed at the proxy plant.

The IOUs compare the MPR with the bid price during the bid evaluation process described below. Bidders submit one all-in price over the term of the contract; if the bidder does not submit an all-in price, the IOU will calculate it based on the data provided in the bid. The MPRs are calculated for baseload or peaking proxy plants, so the IOU can readily compare the bid prices for those products with the appropriate MPR in an "apples-to-apples" comparison.

Bids from "as available" resources, however, do not conform to the baseload or peaking MPR. In such cases, the CPUC directs the utilities to blend the baseload and peaking MPRs using a weighted average of the two to develop an MPR for as available resources. The CPUC states that this is an initial methodology that the CPUC will likely revise in 2005. The current process for developing an as-available MPR follows:

1. The IOU will apply the peaking MPR to a fixed number of hours, derived by multiplying the capacity value of the proxy peaker plant by the number of hours in the year (e.g. 20 percent capacity factor x 8,760 =1752 hours).[6]

2. The bidders provide an estimate of the number of hours they expect to deliver energy during peak hours (consistent with guidance IOUs give to bidders in the solicitation). The number of hours of on-peak delivery is compared to the number of hours from step 1.

3. The utility applies a weighted average to the baseload and peaking MPRs to calculate the blended MPR. In the example provided by the CPUC, "If a solar thermal facility offered 2,500 hours per year of peak-oriented deliveries, then the pricing could be benchmarked against a weighted average of peaking MPR (1,752 hours [derived in step #2] and the baseload MPR (748 hours).

Through this process, the IOU calculates the blended MPR that can be compared with the bid price of the as-available product. The IOUs compare the appropriate MPR (baseload, peaking, or as-available) with the price offered by bidders that the IOUs select as potential contract winners. The CPUC established a process for the IOUs follow in evaluating bids, as described below.

Bid Evaluation – IOU Selection of Least-Cost-Best-Fit Bids

After receiving bids in response to its RPS solicitation, the IOU undertakes a selection process to determine the "short list" of the most attractive bids. The IOU will initiate contract negotiations with the short list of bidders. The IOUs select their short list by evaluating all the bids and ranking them in order of which bids best meet the IOU's long-term resource needs. SB 1078 requires the IOUs to rank order the bids according to "least cost" and "best fit" for the IOU. The CPUC defines "best fit" as ". . . being the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs." The utility will not be excused from its APT simply because the utility believes the electricity products offered are not an ideal match for its projected needs (D. 03-06-071).

The IOUs initially categorize the bids into baseload, peaking and as-available products, and rank each grouping from lowest to highest cost. This “first ranking” simply identifies the bid price that the IOU may later compare to the MPR for that product.

The IOUs then re-rank the bids to account for the, “…indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources” as required by Public Utilities Code section 399.14 (a)(2)(B). Transmission and integration costs are not included in the bid price, but are added by the IOU using proxy prices consistent with CPUC direction. As discussed below, the CPUC has adopted a zero value for integration costs, although the agency did adopt a proxy adder to reflect transmission costs.

Integration Costs

Integration costs reflect the need to match electricity supply and demand in real time to compensate for unexpected fluctuations in generation or load. To assist in calculating integration costs, the Energy Commission assembled a team of independent experts to develop a methodology to estimate the costs associated with integrating renewable resources into California’s electricity system. The results of the Energy Commission’s *Renewables Integration Cost Study* (Integration Study) provided cost information that the IOUs will use to evaluate RPS bids.

The intermittent nature of some renewable resources raises concerns that the fluctuations in the generation profile may impose a cost that needs to be accounted for when the IOUs rank RPS bids. The Integration Study evaluated the cost of “ancillary services” procured by the CA ISO to balance electricity load and generation in “real time.” Integration costs are in part due to “regulation service” in which the ISO procures electricity in four second increments to maintain the system. Integration costs are also due to “load following” services procured by the ISO to supplement the market on a ten-minute basis.

Phase 1 of the Integration Study shows that at present levels of market penetration, the regulation and load following integration costs associated with renewable facilities are negligible. The study recommends that for the first round of solicitations, the IOUs should assign a zero value to the costs. The CPUC adopted this finding, noting that updates to the Integration Study may indicate the need for a non-zero cost for future solicitations (D. 04-07-029 of R 04-04-026).

The CPUC also uses data from the Integration Study to adopt a baseline capacity value for new wind projects. The capacity value is initially set at 24 percent and is based on an average of capacity values from existing wind resources in California. A wind bidder may adopt this capacity value in structuring its bid (e.g. calculating electricity production from the project) and the IOU must accept this assumption. A bidder representing wind facilities has the option to use a higher capacity value, but should be prepared to support such claims with site specific data. Also, the IOUs are not obligated to accept capacity values that exceed the 24 percent baseline. The CPUC adopted the placeholder capacity value for wind to address on-going disputes between generators and IOUs (D. 04-07-029 of R 04-04-026).

Transmission Costs

There are two components of transmission cost: “Direct Assignment Facilities” and “Network Upgrades.” The costs associated with Direct Assignment Facilities are included in the bid price and represent the cost of interconnection between the generator and the first point of interconnection to the transmission grid.

The Network Upgrade proxy costs are calculated by each IOU in its Transmission Ranking Cost Report.[7] The IOUs add this cost to the bids for the purpose of rank ordering by least-cost-best-fit. Network Upgrade costs provided in the Transmission Ranking Cost Report are a proxy for the system upgrade requirements needed to transmit additional generation through the system starting at a specific point of interconnection.

Other Considerations in Bid Evaluation

Bidders have the opportunity to describe the potential benefits from their projects which the IOU will consider in the RPS evaluation process (D. 03-06-071). The IOUs will quantitatively evaluate benefits associated with curtailability, dispatchability, local reliability, and repowering when reviewing bids.[8]

Any benefits identified by a bidder that apply to resource diversity, minority and low income communities, and environmental stewardship are considered “qualitative” attributes by the CPUC. Verified qualitative attributes can be used by the utility to justify moving a bid to the short list.[9]

Following the guidelines established by the CPUC, each utility will evaluate bids received using their unique methodology approved by the CPUC. To help ensure a fair process that properly follows CPUC direction, the utilities’ bid evaluations will be reviewed by a group of non-market individuals who comprise the “Procurement Review Group” for each utility. Each member of the Procurement Review Group will have access to bid data and evaluation methods, and is bound by a confidentiality agreement from disclosing this information.[10]

Disclosure of Market Price Referents

The utility notifies the CPUC when it has selected its short list of bidders, and this is the signal the CPUC waits for before publicly releasing the MPR. Although the general methodology for calculating the MPR is currently public, the CPUC has not calculated the specific cent-per-KWh value. After receiving notification that each utility has selected its short list, the CPUC will publicly disclose the MPR it has calculated. Conversely, the IOUs will not make the bid prices available to the CPUC until after the MPR is released. This process is intended to protect against the bid prices influencing the CPUC's determination of the MPR. Also, the process is aimed at deterring bidders from being influenced by the MPR when they submit their bid prices to the IOUs.

Bids above the Market Price Referent — Supplemental Energy Payments

Bids priced above the MPR (on a net present value basis), not including transmission and integration costs added to the bid for evaluation purposes, may be eligible for SEPs from the Energy Commission. SEP eligibility criteria are discussed in a later subsection.

SEPs are to be paid for the lesser of 10 years or the length of the utility contract, with a further restriction that no SEPs will be made for contracts with terms of less than three years.

The Energy Commission has statutory authority to establish payment caps on SEPs. This could include a cap on the cents per kilowatt-hour SEP, on the amount of funding per project, or the total amount of public goods charge funds available for a given solicitation to achieve the most efficient management of public goods charge funds. At this time, the Energy Commission is not proposing to establish caps in advance, but instead intends to evaluate the bids received in each solicitation and determine the need for caps at that time.

Any caps would be established by the Energy Commission within 30 days of receiving information about prices of the winning bidders. If public goods charge funds are insufficient or unavailable to cover the above-market costs, a utility can limit its annual procurement to that quantity of eligible energy that can be procured with available SEPs. As stated previously, if public goods charge funds are inadequate to cover the bid price, the CPUC may excuse the IOU from fully procuring its APT that year without penalty.

Applying for Certification and Pre-Certification

Any facility operator interested in generating electricity that will count towards an IOU's RPS obligation must certify the facility with the Energy Commission. This applies to all facilities regardless of whether or not they previously registered with the Energy Commission's Renewable Energy Program. Guidebooks and application forms are available on-line at [www.energy.ca.gov/portfolio]. An application may be submitted for a facility by the facility operator (CEC-RPS-1) or by the procuring IOU on the operator's behalf (CEC-RPS-2) for facilities under contract with the IOU prior to April 21, 2004.

Provisional or "pre" certification as an eligible renewable resource is available for applicants whose facilities are not yet on-line. The information submitted by these applicants will be subject to further verification once the pre-certified facility has been completed.

The Energy Commission will review the certification application to determine eligibility and will notify the applicant if it is eligible for the RPS or the RPS and SEPs. Applicants can expect to be notified within 10 to 30 days, depending on the complexity of the application.

If the Energy Commission approves an application for certification or pre-certification, the Energy Commission will issue a certificate stating that the facility is certified or pre-certified as eligible for the RPS, or eligible for the RPS and SEPs, as appropriate. Certification is subject to regular updates and the Energy Commission may conduct random audits or site inspections to verify compliance with the eligibility criteria.

Eligibility for Supplemental Energy Payments

To qualify for SEPs, a facility must be certified by the Energy Commission and must begin commercial operations or be repowered on or after January 1, 2002, or such later date as determined by the Energy Commission. Eligible renewable facilities must compete for SEP funding by participating in competitive RPS solicitations to be held by PG&E, SCE and SDG&E (or, perhaps by ESPs and CCAs once implementation rules are developed for these retail sellers). Bilateral contracts with renewable generators, though they are allowed to count towards the RPS, will not qualify for SEPs.

The Energy Commission may make SEP awards through "Public Goods Charge Funding Awards" which serves as a grant to the project for renewable generation. To receive a Public Goods Charge Funding Award, the winning bidders of utility RPS solicitations must: 1) be awarded a utility contract and 2) complete any required environmental review of their renewable facilities under the National Environmental Policy Act and/or the California Environmental Quality Act. If the winning bidder has not completed all environmental permitting requirements, the Energy Commission may issue the applicant a “Public Goods Charge Funding Confirmation” acknowledging the request for SEPs, and the availability of such funds in a future Public Goods Charge Funding Award.

Once the renewable facilities are constructed and commence commercial operations, the applicants may submit monthly invoices to the Energy Commission to begin receiving SEPs. Payments will only be made for eligible renewable electricity generation.

Rules that Apply when a Bidder has an SB 90 Award

Some projects competing for an RPS power purchase agreement may be in possession of a “conditional funding award” pursuant to the Energy Commission’s implementation of SB 90. Projects cannot receive both SEPs and SB 90 award payments. A project with a conditional funding award from the Energy Commission’s implementation of SB 90 can participate in an RPS solicitation to secure a power purchase agreement, but must relinquish its SB 90 award if it wishes to receive SEPs.

A winning bidder in an RPS solicitation that chooses to keep its SB 90 award can receive payments under the terms and conditions of the SB 90 award, but cannot receive SEPs resulting from the RPS solicitation. A winning bidder that chooses to relinquish its SB 90 award and any payments already made under that award must do so once it executes a contract with a utility. This must be done even if the bidder does not ultimately qualify for SEPs because its bid was below the MPR for that solicitation. If a bidder does not secure a contract under the RPS solicitation, however, the bidder will not be required to relinquish its SB 90 award.

Specifically, bidders with SB 90 awards whose projects have not commenced commercial operations must state in their bid their intention to either (1) keep their SB 90 award and agree to be ineligible for SEPs; or (2) relinquish the SB 90 award and compete for potential SEPs. Bidders with SB 90 awards whose projects are already on-line must do the same, with the further understanding that any funding awarded through SEPs will be reduced by the amount of SB 90 payments already made to these projects.

Multiple Awards

Facilities that divide their electricity generation among two or more separate power purchase contracts can be eligible for SEPs provided that all of the generation from each contract is reported to the Energy Commission’s RPS tracking and verification system. Facilities, however, are only eligible for SEPs for the first 10 years of generation and only for their initial RPS contract(s) should they enter into subsequent RPS eligible contracts.

Tracking Progress

The Energy Commission has the lead responsibility to track and verify the IOUs procurement of RPS eligible energy. The Energy Commission is developing a regional tracking system that will provide an effective tool for tracking RPS compliance, as described in Chapter 4.

As noted above, the CPUC is the lead in setting the APT and ensuring the IOUs meet their annual procurement obligations. Although the IOUs have some compliance flexibility, the CPUC may also direct the IOUs to procure more renewable energy than the minimum annual incremental amount required by law.

Both the CPUC and Energy Commission will work closely to ensure that the RPS targets are met.

Notes

[1] CPUC Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program, R04-04-026, mailed April 28, 2004, and CPUC Opinion Adopting Standard Contract Terms and Conditions, D.04-06-014, June 9, 2004.
[2] California Public Utilities Commission, "Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program: Rulemaking 04-04-026," [http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/36206.doc], accessed July 16, 2004. Also, California Public Utilities Commission, *Opinion Adopting Standard Contract Terms and Conditions*, Appendix B, D.04-06-014, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37401.htm], accessed July 15, 2004.
[3] These figures are from D. 04-06-014 Appendix B, and are revised from the targets initially put forward in the Order Instituting Rulemaking 04-04-026.
[4] Note that in a letter dated June 25, 2004, the CPUC excused SCE from holding an RPS solicitation in 2004. The letter stated: "The Energy Division finds that SCE's 2004 renewable procurement plan is in compliance with D.04-06-014. In addition, SCE has met their 2004 annual procurement target making a solicitation unnecessary at this time.
[5] The CPUC adopted the methodology to calculate MPRs in the July 8, 2004, "Opinion Adopting Criteria for the Selection [of] Least-Cost and Best-Fit Renewable Resources," Decision 04-07-029, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/38287.htm], accessed July 28, 2004.
[6] The CPUC will not disclose the capacity factor it assumes for developing the peaker MPR until after the CPUC makes the MPR public. The timing for making the

MPR public is described in the subsection of this appendix titled, "Disclosure of Market Price Referents."
[7] CPUC, April 2, 2004, "Administrative Law Judge's Ruling Proposing Interim Methodology for Development and Consideration of Transmission Costs in Renewable Portfolio Standard Procurement," part of Investigation 00-11-001.
[8] CPUC, July 8, 2004, "Opinion Adopting Criteria for the Selection [of] Least-Cost and Best-Fit Renewable Resources," part of Rulemaking 04-04-026, Decision 04-07-029.
[9] CPUC, July 8, 2004, "Opinion Adopting Criteria for the Selection [of] Least-Cost and Best-Fit Renewable Resources," part of Rulemaking 04-04-026, Decision 04-07-029.
[10] CPUC, July 8, 2004 "Opinion Adopting Criteria for the Selection [of] Least-Cost and Best-Fit Renewable Resources," part of Rulemaking 04-04-026, Decision 04-07-029.

Appendix C. Summary of Public Comments from the May 4, 2004 and June 8, 2004 Committee Workshops on Accelerated Renewable Energy Development (Central-Station and Distributed Generation)

Introduction

This appendix summarizes parties' docketed comments from two workshops held in support of the *2004 Energy Report Update*: the 2004-2005 IEPR Committee workshop held on May 4, 2004, and the IEPR Committee and Renewables Committee joint workshop held on June 8, 2004. The workshops were conducted to seek input on accelerated renewable energy development and renewable distributed generation in California, as part of a process identified in the *2003 Energy Report* to examine accelerated renewable energy development.

All interested parties were encouraged to submit written comments in response to specific questions posed in the workshop notices. Interested parties were also encouraged to participate in the workshop discussions and several workshop participants provided PowerPoint presentations, which were later submitted to the Energy Commission docket. All docketed comments, workshop presentations, and a transcript of each workshop can be viewed at: [http://www.energy.ca.gov/2004_policy_update/documents/index.html].

This appendix contains four times:

- Questions asked at the May 4, 2004 workshop
- A staff summary of docketed comments for the May 4, 2004 workshop
- Questions asked at the June 8, 2004 workshop
- A staff summary of docketed comments for the June 8, 2004 workshop

Questions on Accelerating Renewable Energy Development

Accelerated RPS Goals Beyond 2010

Renewable energy development in California is currently progressing through incentives provided under the Renewable Energy Program (REP), established in 1997 and continued in 2002 by SB 1038, and a Renewables Portfolio Standard (RPS), established in 2002 by SB 1078, which requires retail sellers to increase their sales of electricity from renewable sources to achieve 20 percent by 2017. Since the RPS legislation was passed, three state energy agencies have adopted the *Energy Action Plan*. (The three agencies are the California Energy Commission, California Public Utilities Commission, and the California Power Authority.) The *Energy Action Plan* establishes a more aggressive goal for renewable energy development, with a target of 20 percent by 2010. In the *2003 Energy Report,* the Energy Commission confirmed support for the target of 20 percent by 2010 and concluded that more ambitious, longer-term goals may be warranted for the post-2010 period.

1. Should the state pursue additional renewable development beyond 20 percent of retail sales by 2010 through either mandates or incentive structures?
2. What benefits and barriers are there associated with accelerated renewable development beyond 2010?
3. How and when should the state's accelerated goals be articulated, implemented, and evaluated?
4. How should these goals be adjusted as transmission availability, resource availability, and/or costs change?

Re-calibration of Specific Utility Goals

The *2003 Energy Report* further recommended that three issues should be considered in establishing more ambitious RPS goals: the specific resource mix of each utility, transmission infrastructure, and the availability of cost-effective renewable resources. To reach 20 percent renewables by 2010, at least one utility will need to add only a small amount of new renewable energy; others will need to add a large amount. In addition, because of the location-specific nature of some renewable resources, some utilities may have more abundant renewable resources than others. This may mean that individual utility targets should be developed to replace the Legislature's uniform statewide RPS goals.

1. Should RPS obligations differ by utility or retail seller, or should the obligations remain equal statewide as in current law? Please comment on the following alternatives:
2. Each entity achieves an equal percentage of its retail sales from renewables (following the current RPS structure);

3. Each entity achieves an equal percentage of the estimated renewable potential within its service area;
4. Each entity's percentage varies, accounting for differential renewable resource potential, deliverability, costs and value among areas, to maximize overall statewide benefits.
5. How should the varying amount of renewable energy available within each utility area be taken into account?
6. How should the transmission infrastructure, including utilization of existing transmission capability within and among utility areas, be taken into account?
7. How should differential costs of resource development in relation to electricity rates in each area be taken into account?
8. If differential targets make sense economically, should they be mandated or achieved through incentive structures? What mandates or incentive structures would you suggest?

RPS As It Applies to Publicly Owned Electric Utilities

SB 1078 also contains requirements for publicly owned utilities to support statewide renewable energy development plans. In the *2003 IEPR*, the Energy Commission stated its plans to work with the publicly owned utilities to address issues affecting their efforts to implement California's RPS goal.

1. What progress have publicly owned utilities made toward developing plans for achieving the RPS goals?
2. What implementation rules, such as facility eligibility criteria, do the publicly owned utilities plan to employ in implementing the RPS? Do they plan to consider electricity from large hydroelectric facilities as meeting RPS compliance requirements?
3. How can publicly owned utility RPS procurement and transmission planning activities be best coordinated with statewide goals to achieve a cost-effective RPS?
4. Some utilities have green pricing programs in which consumers pay a premium to support renewable energy procurement on their behalf. Should such programs be separate and distinct from procurement aimed at achieving the RPS? In other words, should renewable procurement for green pricing programs be counted towards the RPS?
5. What barriers do publicly owned utilities face in accelerating the RPS target to 20 percent by 2010? In achieving goals beyond 20 percent?

Tradeable Renewable Energy Certificates

Renewable Energy Certificates (RECs) refers to the separable bundle of non-energy attributes or renewable characteristics of renewable electricity generation. The Energy Commission and the Western Governor's Association are presently working together to 1) establish a regional tracking system to provide necessary verification and tracking of RECs in the West for compliance with state RPS programs; and 2) facilitate commercial trading of RECs. The use of tradeable RECs separate from the associated electricity commodity - or “REC-only” transactions - was initially not allowed by CPUC rule for meeting RPS requirements. Many stakeholders have, however, recognized that tradeable RECs are a possible mechanism to meet RPS requirements. [Note: RECs associated with renewable distributed generation will be addressed at a separate workshop.]

The CPUC June 19, 2003 decision regarding RPS states the following:
“Before we consider adoption of a REC trading system, we will need a clear showing that a REC trading system would be consistent with the specific goals of SB 1078 [e.g. public health, economic development, job creation, environmental, and other benefits anticipated by the statute], would not create or exacerbate environmental justice problems, and would not dilute the environmental benefits provided by renewable generation.”

1. What information is available or should be developed to provide a clear showing of the type stated above? What are the necessary features of a REC trading system?
2. How could tradeable RECs be used with in-state delivery requirements under the RPS? What benefits would their use provide in this context? What costs?
3. If a REC trading system is adopted, how should, if at all, a market price referent be established for a REC-only transaction?
4. If a REC trading system is adopted, how should, if at all, supplemental energy payments apply to REC-only transactions?
5. How is the ownership of RECs affected when public goods charge funds support the associated renewable energy in the form of supplemental energy payments or other state or federal incentives?
6. How is the ownership of RECs affected where general ratepayer investment in renewable energy is supplemented by private funding support in the form of green pricing premiums or other funding?

Summary of Docketed Comments from the May 4, 2004 Workshop on Accelerated Renewable Energy Development

Dorothy Boberg, Resident

- Oil is running out. Global warming is happening. Use renewables.

California Municipal Utilities Association (Jerry Jordan)

- CMUA re-submitted the July 15, 2003 letter to Chairman Keese and a summary of publicly owned electric utilities renewable policies (100 plus pages).
- Publicly owned electric utilities have historically supported renewables (geothermal, wind, PV). There are a series of questions that CMUA requests that the Energy Commission ask, and answer, before imposing any RPS requirements on publicly owned electric utilities.

Calpine (Jack Pigott)

Accelerated RPS Goals Beyond 2010

1. Renewables beyond 2010

    - Calpine states that to meet the 2010 RPS, 3,000 MW of baseload renewables or 10,000 MW of wind, or some combination, will need to come on-line. Given the time required to permit, develop, finance, and construct these projects, the contracts will need to be in place this year or next. Calpine does not believe this will happen.
    - States that "progress to date" suggests that 2010 RPS date will not be met.
    - Suggests expediting the current process rather than establishing goals in the more distant future.
    - Wants PTC expanded/extended to all renewable technologies.

2. Barriers of RPS and post 2010.

    - Complexity of RPS legislation and development is a barrier. 18 month implementation process and lack of contracts biggest barriers.
    - Second barrier is "arcane set of eligibility requirements that restrict" (geothermal), specifically geothermal on-line prior to September 26, 1996.
    - Third barrier is "considerable length of time it takes to permit a renewable project in California."

3. Accelerated Goals

- Calpine recommends focusing on 20 percent by 2010 now, and then, if, say, by 2008, it appears that the current goal will be met, focus on farther reaching goals.

Re-Calibration of Specific Utility Goals

1. RPS obligations differ by utility?

    - Calpine recommends keep equal percentages, as current law.

    - If ESP/CCAs are required to pay an exit fee to a utility that is partially attributable to renewable power, then that ESP/CCA should receive credit for that power towards its RPS requirement.

    - Allow ESP/CCAs to comply with their RPS requirements by acquiring renewable energy or RECs on a term equal to their power sales contract (i.e. two year contract, two years of renewable power or RECs, not the standard ten.)

2. Varying Amount of Renewables by Utility
    - Calpine says this should not be taken into account. Utilities can buy from other areas of the state, not just their area.

3. Transmission

    - Sellers should be allowed as much flexibility as possible, without the need for firm transmission rights. No need for seller to demonstrate wheeling path. Sellers should be able to utilize shaping and firming services, similar to BPA wind integration product.

4. Differential costs of resource development

    - Areas where generation is needed, either to relieve congestion or for reliability purposes, should command higher price in the least/cost best fit criteria than projects in less desirable locations.

5. Mandates vs. Incentives

    - Prefer voluntary goals with incentives over mandates. One valuable incentive would be to expedite the permitting process.

RPS as it Applies to Publicly Owned Electric Utilities

- no comments

Tradable RECs

1. Features of REC trading system

    - RECs would benefit CA provided they are coupled with in-state delivery and priced in a manner to insulate ratepayers from fossil fuel prices.

2. How can RECs be used

    - Supports RECs with in-state delivery requirements. Allow shaping when delivered with brown power and can better meet the utilities requirements.

3. MPR for RECs?

    - There should not be a MPR for a REC-only transaction.

4. SEPs for RECs

    - REC only or RECs with brown energy should not be eligible for SEPs. SEPs should only be paid to eligible renewable generators, not third parties.

5. Ownership of REC

    - Utilities get RECs under RPS contracts. If no contract, unless otherwise specified, RECs stay with generator.

Capistrano Bay League of Women Voters (Sharon Holdt, President)

- Supports conservation and renewables.

Electric Vehicle Association of Southern California (Philip Hodgetts)

- Favors incentives over mandates.

- Favors energy avoidance (energy efficiency).

- Favors individual businesses or homeowners installing their own energy saving or clean energy devices.

Ellison, Schneider & Harris L.L.P (Douglas Kerner)

- Attachment to IEP comments.

- Under standard offer QF contracts, RECs are not transferred to the IOUs, either on a contractual basis or a policy basis.

- Under the CPUC decision regarding standard offers, the contract was meant to represent a "complete transaction..." Thus, every term meant to be included in the standard was included and no term was omitted which was intended to be included.

- The CPUC determined that environmental attributes were not included within the pricing of the standard offer.

- The standard offer contracts are only for the sale and purchase of energy and capacity.

Law Offices of Diane I. Fellman Steve Probyn Clean Power Income Fund, GRS presentation (8 PPT slides)

- REC trading will allow CA to meet RPS goals efficiently and with the least cost to ratepayer.

- Tradable RECs are consistent with in-state delivery requirements under the RPS resource eligibility definitions.

- Tradable REC systems have used price caps/penalty charge for consumer cost stability (called compliance fee in Mass.) instead of MPR.

- RECs are a property right of generator.

Green Power Institute and the California Biomass Energy Alliance (Reply Comments) (Greg Morris)

These are reply comments in regard to the May 4, 2004 workshop discussions.

Accelerated RPS Goals Beyond 2010

- For the accelerated schedule, couple it with longer-term plan to avoid boom and bust cycle. Plans will ensure a stable, long-term environmental industry for the state.

- The inclusion of an accelerated goal beyond 2010 gives the state a much better chance of building a stable renewable energy industry for the long term, rather than experiencing the same kind of development boom and bust that occurred during the late 1980s, which was followed by more than a decade during which there was almost no new renewable development.

- The SB 1038 funding may not support the 2017 target, let alone the accelerated 2010 target.

RPS as it Applies to Publicly Owned Electric Utilities

- IOUs purchase nearly 80 percent of all California renewables, so the publicly owned electric utilities are lagging.

- The intent of SB 1078 was that 20% apply to everyone. Any effort by the publicly owned electric utilities to procure less or use large hydro may lead to suspicions that publicly owned electric utilities are attempting to avoid compliance.

- ESP/CCAs should be required to comply with the 20 percent target as well.

Recalibration of Utility Goals and TRECs

- To base a utility's RPS on "specified percentage of its estimated renewable endowment" is a "serious mistake." Official estimates would lead to endless work by consultants and analysts, never reaching consensus.

- Percentage of sales is equal for all utilities.

- For the most part, smaller providers, like publicly owned electric utilities, ESP/CCAs etc., do not have the ability to enter into long-term contracts with renewable providers. For this segment of the market, separable REC trading may offer the best opportunity for providers to efficiently achieve RPS compliance.

- However, greatest danger of a REC market is that it could lead to double-counting, gaming or other market manipulation. This party asks that a full record be developed surrounding REC trading before any decisions are made.

Stephen Heckeroth (9 PPT slides)

- Reiterates candidate/governor Schwarzenegger's commitment to solar PV.

- Favors distributed generation over central station.

Lyn Harris Hicks, Resident

- Decentralize California’s energy production for security reasons.
- Independence from foreign and domestic energy manipulation.
- Protect our ecosystem.

Independent Energy Producers (Steven Kelly)

- The QF Standard Offer contracts of the 1980s and 1990s were silent on the matter of environmental attributes. Therefore, they could not be construed as providing a means of transferring ownership of environmental attributes associated with QF power generation. Thus, the environmental attributes have never been sold, thus the QF remains ownership and retains the right to sell the property to any willing buyer.
- For the RPS, if the state wants to count the renewable energy, they should do so. However, the REC would remain with the generator. With the policy of "no double counting" firmly in place, the generator should be allowed to sell the REC to any willing buyer.
- The Commission should approach the WGA to seek their endorsement of the "no double counting" principal throughout the region.

SCE (Berj K. Parseghian)

- These are reply comments in regard to the May 4, 2004 workshop discussions.
- Goals beyond 20% by 2010 is "premature." Actual experience in procurement pursuant to the RPS legislation is needed in order to allow policy makers to understand the cost associated with current procurement goals and any revision to those goals.

Solargenix (Tod O'Connor and Mark Skowronski)

- These are reply comments in regard to the May 4, 2004 workshop discussions.
- If legislation is enacted to increase/extend the RPS, recommend sufficient funding to handle increased number of contracts priced above MPR. Two provisions - make sure PGC funding coincides with new date and have IOUs

make a payment to SEP account if their renewable contract is under MPR. The IOU payment would be the difference between MPR and the contract price. This IOU payment would in turn be available to other renewable projects that need SEP payments because they are above the MPR.

- Solargenix supports "fair and equitable RPS goals that are unique and specific to each IOU" with respect to where the resource is located. REC market could alleviate this discrepancy.

- Publicly owned electric utilities should comply with the RPS, even if it means they need to aggregate their sales/load, like the Southern California Public Power Authority or the Northern California Power Agency. A REC market would make it easier for publicly owned electric utilities to comply with RPS. Legislation is required to compel publicly owned electric utilities to devote portion of PGC funds to renewables.

- REC market key to publicly owned electric utilities and IOU RPS goals. RECs should be allowed instead of power contracts. RECs should be valued differently based on the type of generation (i.e. wind is "as-available vs. solar thermal is "on-peak", therefore wind worth less).

Valley Electric Association (Louis Holveck)

- Small publicly owned electric utilities with 16,000 + customers, most in Nevada, 32 total in California.

- SCE provides wholesale power to CA customers.

- Valley Electric Association provides wholesale service to several SCE areas.

- RPS for Valley Electric Association is "not feasible." RPS for Valley Electric Association is "impractical and cost-prohibitive." Requests exemption from California RPS.

- Valley Electric Association is already exempt from Nevada RPS because it is a publicly owned electric utility.

Questions from the June 8, 2004 IEPR Committee and Renewables Committee Workshop on Renewable Distributed Generation

1. How should state and local programs be coordinated in terms of incentives? How formal or informal should this coordination be?

2. The Emerging Renewables Program offers incentives to help commercialize emerging renewable technologies, create economies of scale, and support the development of a competitive market environment to help bring down the cost of emerging renewable technologies. Over time, it is expected that incentives will no longer be necessary to support further development, as the technology becomes competitive in its own right. This strategy appears to have been successful in establishing the largest market in the world for renewable distributed generation, which is in Japan, where declining incentives for PV installations have nearly been phased out. Is this an effective long-term strategy for California, or should it be altered? In particular, please comment on the following:

a. In California, are we achieving program goals of bringing about cost reductions so that we are close to reaching the point in time where incentives are no longer necessary?

b. What is the expected outlook in cost reductions for retail purchase of these distributed generation systems?

c. What could be done to accelerate reduction in costs of renewable distributed generation technologies? If additional funding is necessary to support renewable distributed generation technologies as costs are declining, how much support should be provided and for how long? What would be the source of funding?

d. What is the strategy of the PV and small wind industry if support from state incentive programs for their technologies is phased out?

3. Should the state pursue a strategy similar to the German model of providing incentives to produce renewable distributed generation, rather than incentives to install renewable generating systems? If so, how should such a performance-based incentive program be structured and funded? How would the state transition from the current incentive model, which is similar to the Japanese model, to a performance-based model similar to the German model?

4. Germany and Japan are the world leaders in installing distributed PV generation systems, followed by California. What lessons can California learn from these successes?

5. Many distributed renewable generation systems are also supported by allowing net metering for the installed site, exemption from cost responsibility surcharges for

on-site generation, and state tax credits or tax exemptions. Generally, these policies are capped or scheduled to expire at some date. Keeping in mind the expectation for declining costs and funding challenges, should the state revisit these support policies? In particular:

a. Should the caps or expectations on these policies be reexamined in light of the strong recent demand? What opportunities and problems would this be likely to create?
b. What is the status of net metering in California? Which utilities are coming close to the cap? When do they expect to reach it? What policies are they planning to adopt once the cap is reached?
c. Should incentives be adopted to encourage utilities to allow additional net metering beyond the cap set in AB 58? What type/level of incentives would you recommend?
d. Should the state's solar tax credit be extended beyond 2005? If so, how should this credit be structured? Would passage of a federal tax credit affect continuation of a state tax credit?
e. Is there any near-term necessity to examine the exemption from cost-recovery surcharge of some distributed renewable generation installations in light of the cost-recovery surcharge caps?

6. How should the state establish a program to foster installation of solar systems on new homes built in California? In particular:

a. What should the near-term and long-term goals be for solar on new homes? Should the state establish numerical targets for these goals?
b. Should mandates, incentives, or some other strategy be used to foster solar on new homes?
c. What are the opportunities and barriers to increasing the market penetration of solar systems on new homes in California?
d. To what extent would it be appropriate to modify California building codes to require new buildings to be solar ready? Should solar on new homes be mandated; if so, at what level, size, or percentage? What are the consequences of having a mandate for solar on new homes? Under what circumstances should a PV system qualify for compliance credits in meeting the building energy efficiency standards? What are the consequences of such a credit?
e. What role can investor-owned utilities and municipal utilities play in delivering solar on new homes in their service areas?
f. What role can builders play in delivering solar on new homes to their customers?
g. How should a program for solar on new homes be coordinated with existing incentive programs, if at all?

Summary of Docketed Comments and Presentations from the June 8, 2004 Workshop on Renewable Distributed Generation

Tom Barron - resident Lafayette, CA

- There should be a "total tax credit available" which would be reduced by any local incentive.
- Favors continuing incentives and tax credits.

California Building Industry Association (Bob Raymer)

- PV systems are rarely cost-effective for a new homebuyer. This is due to the State's very stringent energy efficiency standards.
- To make PV economically viable for homebuyers, BIA suggests one or more economic "offsets" or "incentives" must be available. Recommends using one of the 60+ jurisdictions that are already partnered with the building industry's efficiency programs.
- Those options are:

  1. direct cash incentive (likely too expensive given State's budget issues)
  2. local planning incentives (non-cash), such as CEQA reforms, expedited permitting, and "lot bonus density increases."
  3. local fee reductions
  4. energy efficient mortgages
  5. inclusionary zoning
  6. liability protections (whole system must last 20 years, not just panels; inverter fails in 5 to 10 years)
  7. compliance credits - could let PV have some credit, but this would be a step in the wrong direction

Cal SEIA, (Jan McFarland)

- Solar codes should be the same statewide.
- Solar incentives are still needed today, and probably on a declining level for the next decade. It would be disastrous for the industry if any radical changes happen now.
- For solar to become commonplace, four things need to happen:

  1. continued, declining, rebates

2. elimination of net metering cap
3. REC ownership goes to owner
4. continued exemption from exit fees and standby charges

- Solar costs will only decline with long term policies/commitments. The "boom and bust" cycle is hurting the industry and keeping costs up.

- CAL SEIA supports a performance-based incentive pilot.

- The aggregate net metering cap should be completely eliminated to encourage high-density, transmission constrained communities (San Diego, Oakland, San Francisco) to invest in solar.

- CAL SEIA does not see the need to re-examine the cost-recovery surcharge issue at this time.

- CAL SEIA supports the "50 percent of all new homes having PV" goal by 2009/2010 time frame. However, energy efficiency must be the first priority. At this time, CAL SEIA prefers to work with voluntary builders and industry over mandates.

- Biggest barrier to large PV market penetration is depletion of incentive money at the CPUC and Energy Commission.

Energy Ideas, LLC (Joe McCabe)

- 8 points on solar:

    1. CalSEIA can work with mitigated negative declarations to require building-integrated PV where full environmental impact reports are not performed.
    2. Allow PV to count towards IOU's RPS.
    3. [The Energy Commission's] Public Interest Energy Research Renewables [Program] has greatly helped with aesthetically pleasing building-integrated PV.
    4. Site PV in areas with grid-capacity issues.
    5. Solar thermal is more effective than PV.
    6. Costs for PV vary greatly.
    7. Administer the $10 million in the Emerging Program like the New Account - use an auction with bids.
    8. Have various departments within the Energy Commission work better together.

PG&E (Randall Litteneker)

- PG&E is supportive of PV, distributed generation, and net metering, as evidenced by their support of the following:

  1. AB 58 (1 MW net metering bill)
  2. AB 2228 (net metering to biogas digester projects)
  3. AB 1214 (net metering to fuel cells)
  4. AB 1685 (extension of the Self-Generation Incentive Program through 2007)

- PG&E supports a high level of coordination between incentive programs, including the CEC and PG&E/CPUC. Supports the CEC's flexibility to respond to market conditions quickly.

- PG&E has not seen price reductions for PV over the last three years.

- PG&E has recommended that the CPUC rebate level match the CEC level.

- PG&E wants to offer the CEC-level rebate to the waiting queue as money becomes available. If projects take it, great, if not, offer it to the next project in the queue.

- PG&E has not seen noticeable price drops.

- Key to reducing PV costs is to have long term plan, including declining rebates levels.

- PG&E somewhat supports performance incentives because customers will monitor systems; "shop around" for best installer; the system will stay in place; and rewards "tracker" systems. However, who and how the DG output will be monitored and paid for needs to be factored into any decision.

- To reduce PV costs, rebates must decline over time, otherwise no incentive to bring down cost.

- The aggregate net metering cap should not be expanded until a cost-benefit analysis has been conducted and shown to be beneficial to other ratepayers. The Legislature put a cap on the amount of cost-shifting from one set of customers (net metered) to another (no net metering) for a reason.

- PG&E does not have a policy in place once the net metering aggregate cap is reached (because it is somewhat far off).

- Cost-recovery surcharge caps do not need to be re-examined now because there is still a lot of room under the cap.

- PG&E states that because there is still much to learn with regards to large scale PV penetration, that solar subdivisions should proceed with incentives, targets or goals now, and possibly mandates in the future. If a mandate is ordered, it should fall on IOU and publicly owned electric utility ratepayers equally.

SMA (Kent Sheldon)

- Proposes a performance test for inverters by a Nationally Recognized Testing Laboratory. This test would "level the competitive playing field" between inverter manufactures (some who over-report their efficiency for rebate purposes).

Sempra/SDG&E (Bernie Orozco)

- Energy Commission should examine the potential of integrating PV into future changes to Title 24.

- If cost effective, incentive programs should strive to be structurally similar, but allow some local flexibility.

- All state renewable programs should work together - thus, all should be performance based (New/RPS, Existing, Emerging).

- SDG&E C10 made net metering recommendations to the CPUC on May 17, 2004.

US Home (Sherman Haggerty)

- The Emerging Renewables Program should be changed to allow builders to reserve a percentage of homes (without specific address) with PV for Emerging funds.

- Revise Title 24 calculations to allow a builder to obtain energy credit for 75 percent of the energy produced by PV. This would result in homes that use less power, and provide builders flexibility.

Appendix D. Summary of Public Comments from the October 20, 2003 California Public Utilities Commission — California Energy Commission Collaborative Staff Data Request: Inviting Comments on Renewable Distributed Generation in the Renewable Portfolio Standard Program

Public Comments on RPS for Distributed Generation

Both the Energy Commission and the CPUC have identified the need to develop rules and guidelines regarding the eligibility of renewable distributed generation within the California RPS.[1] [2] Now that the agencies have adopted the most essential RPS program structures, they are positioned to address the remaining outstanding RPS issues that have not been resolved, including issues of renewable distributed generation eligibility and treatment. Schedules and processes for concluding these issues will be established over the coming months.

The CPUC and Energy Commission RPS collaborative staff articulated unresolved issues relevant to distributed generation in the RPS, and solicited public input on October 20, 2003. Comments were requested by issuing "CPUC and Energy Commission Collaborative Staff Data Request: Inviting Comments on Renewable Distributed Generation in the Renewable Portfolio Standard Program."

Topics raised by the staff and addressed by parties included:

1. Under what conditions should renewable distributed generation installed on the customer side of the meter be eligible for the RPS? Should special consideration be given allowing the power to be consumed on-site and the REC sold to an RPS-obligated entity?
2. For distributed generation to count toward the RPS, should there be a requirement that a distributed generation owner sign a contract with an RPS-obligated entity or aggregator, and if so, how should such a contract be structured?
3. How should the generation of distributed generation facilities be measured or calculated?
4. Should net metering affect RPS implementation?
5. Should the receipt of public subsidies for the distributed generation facility influence RPS-eligibility?
6. How does the participation of renewable DG affect the REC tracking system (WREGIS) being developed by the Energy Commission?

7. Since the IOUs RPS procurement targets are based on a percent of retail sales, how (or should) DG be reflected in the calculations?
8. How would eligible DG facilities be considered in terms of the solicitations, MPRs, and possible SEPs that are part of the RPS structure for most central-station systems?
9. Is the list of eligible technologies sufficient, or should it be altered to add or subtract particular technologies

The respondents represented a wide range of positions and included representatives from solar industry groups, REC marketers, IOUs, and public agencies. The parties were:

- Bonneville Environmental Foundation
- California Solar Energy Industries Association (CAL SEIA)
- California Coalition of Fuel Cell Manufacturers
- California Power Authority
- The Green Power Institute
- Capstone Turbine Corporation
- City of San Diego
- Vote Solar Initiative
- Enertron Consultants
- Mainstay Energy
- San Diego Gas & Electric
- Southern California Edison and
- Pacific Gas & Electric Company.

All parties agreed that renewable distributed generation should be eligible under the RPS. SCE stated that distributed generation should be eligible "only to the extent that generation is scheduled for delivery and sale to an RPS-obligated utility…. That portion of distributed generation project output used to serve on-site customer load should not be eligible."

The CPUC has determined that on-site renewable energy generation is eligible for the RPS. SCE's suggestion that on-site energy should not be eligible for the RPS would require a revision of that decision. The staff does not have a position on this issue at this time.

All parties except for the three IOUs believed that the RECs associated with renewable distributed generation facilities are the property of the distributed generation owner.

- SDG&E stated that if renewable distributed generation is interconnected under a net metering tariff, then the utility should receive RPS credit. If the distributed generation owner chooses not to enter a net metering agreement, then the credit should stay with the facility rather than being credited to the IOU.

- SCE stated that due to the subsidies already available to distributed generation, no further “special consideration” should be granted.

- PG&E also pointed to the subsidies already paid to distributed generation owners.

RPS collaborative staff at the CPUC and the Energy Commission believes that ownership of RECs for renewable distributed generation is a difficult and unresolved issue. Separating renewable electricity from RECs would require clarification of CPUC Decision 03-06-071, which states that unbundled RECs may not be used to comply with the RPS. Renewable distributed generation is not eligible for SEPs. If unbundled RECs are allowed for renewable distributed generation, then it seems that bids using those RECs for RPS purposes should not be eligible for SEPs, to avoid cross-subsidization.

Aside from economic incentives, it is possible, but not yet clear to the staff, that allowing renewable distributed generation to benefit from both renewable distributed generation incentive programs and the RPS undermines the purposes of these programs. For example, renewable distributed generation incentive programs in the state are plagued by over-subscription. As discussed in Chapter 5, the Energy Commission’s program is expected to be out of funds by the end of 2004.

The remainder of this appendix contains a matrix of comments received in response to the RPS collaborative CPUC and Energy Commission staff data request on this topic.

Matrix of Comments

This section contains a matrix of comments on the seven questions listed above. The matrix lists responding comments for each of the questions asked by staff.

1a. Eligibility: Under what conditions should customer-side DG be eligible?

Bonneville Environmental Foundation	Only if the utility pays for the tags
Capstone	Only if the on-site generator has entered into a contract with the utility allowing the utility to acquire either the REC separately or the bundled REC/energy produced.
CAL SEIA	No Comments
California Coalition of Fuel Cell Manufacturers	We strongly believe that renewable generation installed on the customer's side of the meter should be eligible for the RPS. The State of California has made a consistent set of policy choices to encourage the deployment of distributed generation technologies.
California Power Authority	In principle, renewable DG owners should be eligible to have their power production "counted" toward the load serving entity's (LSE) RPS requirement.
Green Power Institute	Unless the Commission is considering modifying D.02-10-062, the Decision is clear that renewable DG installed on the customer side of the meter is eligible for the RPS program, and that renewable energy that serves to meet on-site load can be counted in the RPS program. For purposes of these comments, the GPI assumes that as a given.
City of San Diego	Owners of customer-side DG should be able to sell their RECs to an RPS-obligated entity, even if energy is consumed on-site. Consistent with the REC being a property right, DG owners should also be able to withhold their RECs.
Vote Solar Initiative	All electricity generated by renewable DG on the customer side of the meter, whether consumed on-site or fed back into the grid through a net metering arrangement, should be eligible for the RPS.
Enertron Consultants	Renewable DG installed on the customer-side of the meter should be eligible for the RPS. Were it not for the DG, the customer would be purchasing that same amount of power from the utility as they are consuming on-site. Thus the RECs associated with the energy consumed on-site should be eligible to be sold to an RPS-obligated entity.
Mainstay Energy	No Comments
SDG&E	SDG&E believes that all renewable DG should be counted towards RPS requirements if the customer has elected to utilize the net metering tariffs offered by the utilities. As part of [net metering], the customer is essentially using the utility to bank excess energy...(above that used on site) that it can use later when its load exceeds generation. Even though under the [net metering] tariff the utility is not “purchasing” the energy, the utility accepts excess energy and returns it at no additional charge when needed by the customer. In return for this tariff service, the utility. SDG&E should receive all RECs associated with the project’s output. If the customer desires to keep the RECs, then it should have the option to not utilize IOU [net metering] tariffs, and thus be entitled to keep all attributes associated with its project.

1a. Eligibility: Under what conditions should customer-side DG be eligible? (continued)

SCE	SCE believes Customer-side DG should be eligible for the RPS only to the extent that it is scheduled for delivery and sale to an RPS-obligated entity as part of a renewable solicitation, meeting all related delivery obligations established by the RPS -obligated entity and not benefiting from any of the incentives extended to DG funded by the ratepayers of the RPS-obligated entities. That portion of DG project output used to serve on-site customer load should not be eligible. Power exported for sale from a DG project and scheduled with the CA-ISO, as described above, is easily metered and accounted for, both as to energy and the associated RECs.
PG&E	It is not clear what the phrase "eligible for the RPS" is intended to mean. … Utility ratepayers have already compensated the DG developer for the renewable nature of the output, so the generation should count toward the subsidizing utility's renewable obligation without further compensation to the DG developer.

1b. Eligibility: Allow separation of the energy from the RECs?

Bonneville Environmental Foundation	Should be separated from the energy.
Capstone	Both options [of allowing the utility to acquire either the RECs separately or the bundled REC/energy produced] should be available so that the on-site generator can contribute to the renewable portfolio using the arrangements that best meet their particular needs. The sale of bundled REC/energy will be appropriate when the utility is both the buyer of the energy and the REC. In this case, the contract should provide that the on-site generator pay only the energy cost of that energy consumed on site and should not be required to pay the utility's transmission and distribution charges.
CAL SEIA	Yes (Inferred from below)
California Coalition of Fuel Cell Manufacturers	For end users to be able to capitalize on the financial value of the RECs, the credits and the energy output must be separated, allowing the end user to sell the REC to an RPS-obligated entity and capture the value of the environmental benefits.
California Power Authority	No Comment
Green Power Institute	Separating RECs from renewable energy and allowing obligated entities to fulfill their requirements by the procurement of RECs alone is a matter to be addressed in future deliberations at the CPUC. Of course, by definition, obligated entities do not procure renewable energy that is generated on the customer side of the meter for on-site use. Thus, if RECs from that kind of generation cannot be separated from the energy, they are unavailable to obligated entities trying to meet their APTs. This negates the intent of D.02-10-062 to allow this energy to count. The solution that is consistent with the fairness principle is to allow RECs from energy that is generated and used on the customer side of the meter to be separated and made available for sale, but only to the utility company or energy service provider that would otherwise serve that load if it wasn't supplied on-site. .
City of San Diego	Yes
Vote Solar Initiative	No Comment

1b. Eligibility: Allow separation of the energy from the RECs? (continued)

Enertron Consultants	There are associated RECs with each MWh of energy from both the customer-sited renewable DG and the central-station renewable facility. Therefore separation of the energy from the RECs from DG facilities should be allowed, which facilitates the energy to be consumed on-site and the RECs to be sold to an RPS-obligated entity.
Mainstay Energy	For customer-sited DG, separation of the RECs from power should be permitted as a fundamental principle. Certificate based accounting is the only practical means to allow DG participation. In terms of RPS participation, there should be no distinction between power consumed on-site and that exported back to the grid for small-scale DG--RECs should be issued for an installation based upon the total AC kWh production of the renewable source. This approach rewards the characteristics of DG that are at the core of its usefulness, the fact that power is delivered to the point of consumption without burden to the T&D network. These unbundled RECs should be then be eligible to be sold to an RPS-obligated entity.
SDG&E	no
SCE	Customer-side DG has already been targeted for a variety of special incentives to encourage deployment (e.g. CEC buy-down program, CPUC self-generation incentive program, tariff exemptions from standby and departing load charges, Net Energy Metering). Through these incentives the ratepayers of RPS-obligated entities are currently “paying” for this generation and are entitled to the environmental benefits already. No additional benefits, subsidies, or “special consideration” should be given to DG facilities with respect to separation of energy from Renewable Energy Credits (RECs), or in eligibility for RPS.
PG&E	The question assumes that the DG developer could sell the renewable attributes of its facility to an RPS - obligated entity. This premise assumes that the renewable attribute of a ratepayer subsidized DG facility could be conveyed to an entity other than the subsidizing utility. PG&E believes this would be contrary to the spirit that motivated the Commission and the Legislature to continue to support the DG subsidy. First, there should be no windfall to DG developers, and secondly, ratepayers should receive the value of a recently-recognized attribute, which was the premise of the ratepayer subsidy in the first place. DG developers should *not* be able to convey the renewable attribute of their subsidized facilities to third parties.

1c. Eligibility: Ownership of RECs

Bonneville Environmental Foundation	Tags should belong to the system owner. They can be sold to whomever the system owner wishes.
Capstone	on-site generator
CAL SEIA	PV customers
California Coalition of Fuel Cell Manufacturers	We also encourage the staff to consider permitting the owner/operator of the DG asset to own both the energy output and the associated environmental benefits (called renewable energy credits or RECs) of the energy output.
California Power Authority	Additionally, the CPA regrets to see the CPUC/CEC background statement that "only new renewable DG installations are to be credited toward the utility's RPS baseline calculation" (emphasis added). It is our understanding that pre-existing renewable central-station generation certainly counts toward the utilities' RPS obligations, and no different treatment should be applied to DG. … If even treatment requires a change in CPUC position, or in legislation, then we encourage such action.
Green Power Institute	renewable DG owners
City of San Diego	DG owners
Vote Solar Initiative	No comment
Enertron Consultants	DG facility owner
Mainstay Energy	DG owner
SDG&E	Utility if DG participates in [net metering]; otherwise, DG system owner
SCE	Rate payers
PG&E	utility

2a. Relationship between DG owner and RPS-obligated utility: Requirement to sign a contract?

Bonneville Environmental Foundation	The Green Tags from the facility belong to the facility owner unless they are transferred by contract to another party. Owners of distributed generation facilities have various options to sell their tags and the utility could easily be on of those options. New solar distributed generation facilities in Oregon and Washington have the opportunity to sell their tags to Bonneville Environmental Foundation for 10 cents/kWh if they sign an attestation and a contract stating that they sell those attributes to the solar coop from which our purchases. Bonneville Environmental Foundation pays for the tags from all kWhs generated by the system regardless of whether the kWhs are used on site or delivered back to the utility. The environmental benefit is the same.
Capstone	The parties should enter a contractual agreement that will define the commitments and obligations of the seller of the energy and /or the RECs and the RPS obligated entity.
CAL SEIA	A distributed generation owner should be encouraged (but not required) to enter an agreement "attaching" its distributed generation output to some obligor (whether the RPS-obligated entity directly or an aggregator serving such an entity). This will help both quantify the amount of distributed generation installed in California, and form an exclusive assignment of such distributed generation for purposes of crediting RPS obligations. The motivation for an end user to enter such an agreement presumably would be to capture some financial value of the “green” attribute of their distributed generation.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	A DG owner should be encouraged (but not required) to enter an agreement "attaching" its DG output to some obligor (whether the RPS-obligated entity directly or an aggregator serving such an entity). ...
Green Power Institute	There doesn't necessarily have to be a contract between a distributed generator and the obligated entity acquiring the RECs, but the same central clearing house that will monitor REC transfers and retirements for grid-distributed renewables should perform the same functions with respect to the transactions between distributed generators and obligated entities. As discussed above, unless or until REC trading separate from energy sales is instituted in California, RPS obligated entities should not be permitted to acquire RECs from outside of their service territories or customer base.
City of San Diego	The RPS-obligated entity must purchase the RECs from the DG owner for the REC to count towards meeting the RPS obligation. This could be achieved through a contractual agreement between buyer and seller. …Until a REC trading program is implemented, it is necessary for the RPS-obligated entity to contract directly with the eligible DG facility.
Vote Solar Initiative	No Comment
Enertron Consultants	There should be a requirement that a distributed generation owner sign a contract with an RPS-obligated entity or aggregator to clarify the ownership of the RECs from that facility. Such a contract would indicate that the RECs from this distributed generation facility are being transferred (with appropriate compensation) to the RPS-obligated entity for purposes of their RPS compliance. The distributed generation owner would then not be able to claim that their site is “renewable powered”, only that they are “hosting a renewable facility” on their site.

2a. Relationship between DG owner and RPS-obligated utility: Requirement to sign a contract? (continued)

Mainstay Energy	Customer-sited DG should be aggregated through an appropriate entity or aggregator in a contract agreement. This will help to ensure that this generation is certified and measured/estimated properly.
SDG&E	No Comment
SCE	Yes
PG&E	No (inferred below)

2b. Relationship between DG owner and RPS-obligated utility: How should the contract be structured?

Bonneville Environmental Foundation	If utilities choose to place language in their net metering agreements regarding the tags, they should be required to inform customers that other options exist and that the customer is not required to transfer tags to the utility.
Capstone	For small DG (less than 2MW) a standard contract should be developed that establishes the terms and conditions except duration of the contract. It is unlikely that small DG would participate in a bidding or tendering process so to encourage these resources to be offered to the [RPS], the [RPS] obligated entity should make available a standard offer whereby small distributed generation can provide energy and/or REC for a list price. The utility should reserve a part of its renewable portfolio requirement for this small distributed generation. This small distributed generation offering should be closed only when the utility has met its [RPS] obligation.
CAL SEIA	The contractual structure should be similar to that of an intangible asset sale or a typical commercial transaction, and the volume of RECs sold should be based on electrical output as measured by commercial-grade meters and in accordance with Green-E standards. If distributed generation owners want to sell electricity they should sell it using a separate utility tariff, contract, or other agreement (such as a net metering agreement).
California Coalition of Fuel Cell Manufacturers	No comment
California Power Authority	No comment
Green Power Institute	No comment
City of San Diego	For transactions below a certain size (e.g., 1 MW), there could be a standard offer contract for RECs offered by the RPS-obligated entity.
Vote Solar Initiative	Rules governing the transfer of REC should be developed with an eye to ensuring the integrity of the REC trading system, and contracts consistent with that goal should be required.
Enertron Consultants	Through the Pace Project, we are developing standard contracts for procurement of RECs from small PV systems; we would like to work with the CPUC – Energy Commission collaborative staff to have these contracts be useful and usable by DG facilities participating in California's RPS.
Mainstay Energy	The aggregating entities (either RPS-obligated entities or independent aggregators) need to abide by a code of conduct and share information to prevent instances of double counting. A contract entered into by a distributed generation owner needs to have very strict attestation language regarding double selling.
SDG&E	SDG&E believes that the most expedient way to accomplish the transfer of RECs is to make it a specific provision of the NEM tariff. Because customers currently do not have meters capable of measuring generator output, estimates of this output should be used ...
SCE	Power purchase and sale contracts for the purchase of energy and RECs similar to those employed in SCE's recent RPS procurements should be employed for power sold from DG projects to the RPS-obligated entity.

2b. Relationship between DG owner and RPS-obligated utility: How should the contract be structured? (continued)

PG&E	The distributed generation's renewable attributes should automatically count toward the funding utility's RPS, based upon the subsidy already paid to the developer. A contract would not be required for the distributed generation's renewable output to be credited to the utility's RPS; the fact that the renewable attribute flows to the ratepayers in exchange for their support of the distributed generation makes a contract inappropriate. However, it would be helpful for the utility, the Energy Commission, which is charged with tracking renewable attributes, and the DG developer, to have a memorandum of understanding between the utility and the developer to document the credit to the utility's RPS.

2c. Relationship between DG owner and RPS-obligated utility: Other methods to correlate the output and REC facilities to utilities?

Bonneville Environmental Foundation	Trying to place small solar DG in the spot market is unworkable due to the associated costs.
Capstone	No comment
CAL SEIA	No comment
California Coalition of Fuel Cell Manufacturers	No comment
California Power Authority	No comment
Green Power Institute	The same central clearing house that will monitor REC transfers and retirements for grid-distributed renewables should perform the same functions with respect to the transactions between DG generators and obligated entities.
City of San Diego	The DG owner could also sell its RECs into an established market for REC trading, and would be subject to certification and reporting rules designed to prevent double selling of RECs.
Vote Solar Initiative	No comment
Enertron Consultants	No comment
Mainstay Energy	No comment
SDG&E	No comment
SCE	If the arrangements described in SCE's response to Question 1 above are employed, it would not be necessary to set up a spot market or other mechanisms for such sales.
PG&E	No comment

2d. Relationship between DG owner and RPS-obligated utility: Contract for output outside of service territory

Bonneville Environmental Foundation	No comment
Capstone	No comment
CAL SEIA	DG owners should be able to keep their RECs or sell to any other entity including RPS-obligated entities in their service territory or in other service territories, ESPs, business looking for voluntary offsets, or others such as brokers or non-profits.
California Coalition of Fuel Cell Manufacturers	No comment
California Power Authority	We refer back to one of the reasons for the DG provision in D.02-10-062 decision, namely to encourage distribution utilities to facilitate and encourage DG (in their service areas, by served customers). To this end, DG should count toward an RPS-obligation ONLY when the DG is in the distribution utility's service area….
Green Power Institute	unless or until REC trading separate from energy sales is instituted in California, RPS obligated entities should not be permitted to acquire RECs from outside of their service territories or customer base.
City of San Diego	Distributed generation RECs should be available for trading among all RPS-obligated entities, regardless of location with respect to utility service territory or whether the obligated entity is a utility or ESP.
Vote Solar Initiative	No comment
Enertron Consultants	An RPS-obligated utility should be allowed to contract for the output (energy + RECs) from a DG facility outside of its service territory.
Mainstay Energy	RPS-obligated utilities should be able to contract for output of DG facilities from outside of their service area, anywhere else in the state.
SDG&E	No comment
SCE	Using power purchase and sale contracts and adhering to the principle, already established in the RPS procurement process - that is, energy sold by a generation facility is "packaged" together with environmental attributes will obviate any need to "correlate" the output and RECs to RPS targets of obligated entities. Additionally, SCE's proposal would permit RPS-obligated utilities and ESPs to contract with any entity scheduling energy through the CA-ISO.
PG&E	Yes, but only the portion of generation that was NOT subsidized as described above. This would be consistent with the recognition that the renewable attribute may be conveyed separate from the energy, which is being consumed on-site. It would also put renewable DG on par with other renewable resource developers. However, to preserve the ratepayer interest in subsidized DG, before a DG of any sort may convey its renewable attributes, it should first register with the CEC and affirm the amount of DG subsidized by the ratepayers. This should ensure that the amount of generation subsidized by ratepayers should NOT be available for contract to any entity.

2e. Relationship between DG owner and RPS-obligated utility: How should these rules change to allow ESPs to meet their RPS targets?

Bonneville Environmental Foundation	No comment
Capstone	No comment
CAL SEIA	No comment
California Coalition of Fuel Cell Manufacturers	No comment
California Power Authority	[DG] should count for ESPs ONLY when the DG is located on the site of a served ESP customer. There should be parallel treatment of both regulated utilities and ESPs so as to encourage each to facilitate DG installations by their customers/clients.
Green Power Institute	The rules for all obligated entities, including utilities and ESPs, should be same in this regard.
City of San Diego	No comment
Vote Solar Initiative	No comment
Enertron Consultants	Similarly, an ESP should be able to contract for the output (energy + RECs) from a DG facility for meeting RPS compliance. More discussion about how this can be appropriately metered is found in the response to issue 3.
Mainstay Energy	ESPs should be able to meet their RPS targets with DG.
SDG&E	No comment
SCE	No comment
PG&E	The needs of an ESP renewables program cannot reasonably be anticipated at this time; however, the Commission should continue to ensure that subsidized renewable DG developers do not become eligible to receive a windfall from ESPs, as that would create an incentive to convey the attributes to ESPs and deny the credits to utilities.

3a. Output Calculation: Best method of calculating the contribution of RPS-eligible customer-side DG facility

Bonneville Environmental Foundation	Output should be metered.
Capstone	No Comment
CAL SEIA	RECs should be measured using commercial-grade meters that measure how much gross AC electricity comes out of the inverters. Measurements should be required, rather than estimated, for PV systems greater than 30 kilowatts. It is very easy to track RECs using commercial-grade meters and it is already being done at numerous PV installations around the state. The PUC should come up with a list of "eligible metering equipment" similar to the CEC's eligible equipment list for PV and inverters. The PUC should also develop an accepted format for regular, periodic REC reporting from REC generators to REC customers that is consistent with Green-E standards.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	RPS compliance is predicated on actual renewable energy production and use, not on the amount of renewable generating capacity available to an obligated entity. Therefore, for grid-distributed renewables, RECs will only be issued for actual, metered output. To do anything less for customer-side DG would be problematic in the extreme, even given the fact that metering at small scale is expensive.
City of San Diego	Output of eligible DG facilities should be metered for the purpose of quantifying RECs.
Vote Solar Initiative	Where meters exist, they should be used. … For smaller systems where meters are not prevalent, given the relatively small amounts of electricity at issue, an estimate is appropriate.
Enertron Consultants	The best method of calculating the contribution of RPS-eligible customer-side DG facilities is by reading the AC output of the inverter. This will provide the gross AC generation of the DG facility. This can be read annually by the DG owner and reported to either the RPS-obligated utility that is purchasing the RECs or the aggregator that is combining the output of multiple DG facilities for sale to the RPS-obligated entity. Efforts are underway in the Pace Project mentioned earlier to collect this information on an annual basis through a remote communication interface to the inverter.
Mainstay Energy	Metering required for large systems (30 kW or greater). Estimation used for small systems.
SDG&E	SDG&E does not believe that the amount of power exported to the grid in [net metering] situations is sufficient to treat it as exported to the grid. In situations where a customer desires to sell to its host utility or another utility, it would have to meet all California Independent System Operator (ISO) and Scheduling Coordinator requirements.

3a. Output Calculation: Best method of calculating the contribution of RPS-eligible customer-side DG facility (continued)

SCE	As stated in the response to Question 1 above, DG output used to serve on-site customer loads should not be eligible for the RPS. Power exported to the grid without sale to an RPS-obligated entity should be disregarded for RPS considerations. Such exports are inherently incidental and intermittent, and not subject to performance obligations. Their real contribution to RPS obligations is uncertain at best.
PG&E	The best method would be to estimate the capacity based upon information provided as part of the SGIP process and apply the CEC's generation curve for that type of renewable technology to estimate its generation.

3b. Output Calculation: Are meters required?

Bonneville Environmental Foundation	Meters should be required.
Capstone	No Comment
CAL SEIA	Yes, but do not require a utility-owned or utility-monitored meter on any PV system even if RECs are sold to RPS-obligated entities.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	Net metering law prevents utilities from requiring two meters to measure both gross and net generation. It is the GPI's position that participation in the RPS program will require DGs to meter their gross output, in order to be able to issue RECs for energy used on-site as well as energy exported to the grid. Alternatively, a net metered DG could choose to only claim the RECs associated with its export to the grid, in which case a second meter would not be required.
City of San Diego	No Comment
Vote Solar Initiative	Where meters exist, they should be used. In the case of photovoltaics, larger systems are typically installed with meters that measure kWh production, primarily as a way of monitoring performance and alerting owners to malfunctions.
Enertron Consultants	The CEC's current guidelines under the Emerging Renewables Program require that any system installed after March 31, 2003 "be installed with a performance meter so that the customer can determine the amount of energy produced by the system." For most systems that meet these criteria, the performance meter is part of the display on the inverter. For those facilities installed before this date that do not have inverters or meters that provide this information, the output can be estimated.
Mainstay Energy	A metering device should be required for DG installations over 30 kW in output, something that specifically measures the AC KWh output of the renewable. The meter does not need to be utility billing grade; accuracy to a few percent is sufficient.
SDG&E	No Comment
SCE	No Comment
PG&E	PG&E encourages the Commissions not to require special metering simply for RPS administration. RPS calculations could be based on actual data if available, and based on estimates if metering data is not available. Meters would be required if a portion of the generation were not consumed on site, the Commission determined that ratepayers had no equitable claim to the energy because the subsidy covered less than all of the generation, and the generator wished to convey the renewable energy credit. In that case, the entity, and not the ratepayers, should pay the cost of monitoring output that becomes eligible for compensation.

3c. Output Calculation: Is an appropriate estimation method available?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	Measurements should be required, rather than estimated, for PV systems greater than 30 kilowatts.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	A standardized calculation methodology would incorporate the system's PTC rating, a dc/ac conversion factor, degradation over time, and local solar insolation. There is precedence for this approach—variations of this approach are currently being used by Arizona and Australia. Any consideration of a line loss factor should account for the likely distance from generation to consumption in typical DG scenarios. It may be appropriate to set up different systems for different renewable technologies.
Enertron Consultants	A formula similar to the following is often used to estimate production in the solar industry: Estimated Output = CEC Rated AC Capacity x 5 hours/day average solar insolation x adjustment factor (to reflect line losses, dirt accumulation, etc.)
Mainstay Energy	For small systems, an estimation methodology is sufficiently accurate to issue RECs. If a metering device exists, it should be used in the manner shown above with Medium and Large DG.. In the absence of a meter, the approach that I would recommend is the approach taken by the Australian Office of the Renewable Energy Regulator (http://www.orer.gov.au/generators/index.html). An alternate approach, a little more complex and a little more accurate, would be to combine this approach with a methodology such as PVWatts: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/ Here, you include a factors such as tilt and azimuth to make the estimation more accurate. A degradation factor over time could also be used.
SDG&E	No Comment
SCE	No Comment
PG&E	The CEC should utilize existing or develop new models of renewable generation output for various kinds of technologies, for consistent estimation calculations.

3d. Output Calculation: Who should fund the purchase and installation of the meters?

Bonneville Environmental Foundation	They should be at the facility owner's expense as long as the facility owner also owns the tags.
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	In the case of net-metering installations, the DG owner would have the option of installing a meter to measure gross generation and would be responsible for the cost of the additional meter.
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	No Comment
PG&E	PG&E believes that the DG developer should bear the cost of metering if the developer seeks to convey the non-subsidized portion of its output, as the Commission sought to limit the amount of subsidy to DG developers to the explicit SGIP subsidy.

3e. Output Calculation: How should the meter requirement be structured for net-metering installations?

Bonneville Environmental Foundation	As stated elsewhere, the facility owner should own the tags. Customers should be paid for all the tags their systems generate It would be simple to state that net metering is an exchange of power and that hence all the electricity generated by the system qualifies.
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	A net metered DG could choose to only claim the RECs associated with its export to the grid, in which case a second meter would not be required.
City of San Diego	If the DG owner elects not to measure the gross output of the facility, it may continue to participate in the net metering program, but only RECs associated with the net-positive output of the facility would be allowed to be offered for sale to an RPS-obligated entity.
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	No Comment
PG&E	No Comment

3f. Output Calculation If meters are not required, how should output be consistently estimated across the state? (no comments were received on this question).

3g. Output Calculation: Periodically verified?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	Reporting obligations should be backed by appropriate auditing authority between the parties to a REC transaction. For example, any RECs provider should be required to maintain appropriate records of kWh production (or estimated production, for systems 30 kW or smaller), and any RECs purchaser should be entitled to audit the DG owner's equipment and records to validate reported performance.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	An initial testing program to verify accuracy of estimates [of the system output] should be sufficient—as the controlling factors are not subject to much change, periodic sampling shouldn't be necessary. It should not be necessary to set up a meter reading program, as doing so would entail significant administrative costs. A program by which DG owners self-read their meters and report output, along with a legal attestation to accuracy, should be sufficient. Although the possibility for cheating exists, inflated output numbers would be easy to identify by comparing outputs to system capacity ratings.
Enertron Consultants	For facilities that are net metered, verification can be accomplished through random checks of the e-net output to verify that the output is similar to previous years. For systems where the entire output is consumed on-site, verification can be accomplished through random checks of the energy consumption to determine if it is stable. Additionally, site visits can be conducted on a spot basis to verify that systems are operating at the level expected.
Mainstay Energy	A large-scale meter-reading program is not necessary. The aggregating entities could contact the DG owners on a quarterly basis and request a self-read from the installation meter. This reading would be accompanied with strong legal attestation language, and be run through a "sanity check" to ensure that it was a reasonable reading for that class of system in that area. I would recommend that it be a requirement of the aggregating entity to contact the site owner on a yearly basis in order to receive an attestation regarding the following: • Whether the DG is currently operational • How many days during the previous year the DG was not operational Aggregating entities could be required to perform a (small) random sampling of generators to ensure that they were still active.
SDG&E	No Comment
SCE	No Comment
PG&E	No Comment

3h. Output Calculation: Should a line loss factor be applied to output sold into the grid?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	A line loss factor should not be applied to output that is sold into the grid from a customer-side DG facility.
Vote Solar Initiative	Any consideration of a line loss factor should account for the likely distance from generation to consumption in typical DG scenarios.
Enertron Consultants	Line loss factors should not be applied to output that is sold into the grid, since the output is applied at the distribution level. In fact, previous PG&E studies have shown that appropriately sited DG support the distribution system…
Mainstay Energy	There does not need to be any special treatment of power exported to the grid without sale to an obligating entity. If the DG owner generates RECs for the entire output of the renewable, then the system becomes indifferent as to whether the power is consumed on site or exported.
SDG&E	No Comment
SCE	No Comment
PG&E	PG&E cannot locate any findings regarding line loss factors on the page cited. Perhaps this issue should be discussed in a workshop setting.

3i. Output Calculation: How should power be treated that is exported to the grid without sale to an obligated entity?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	As discussed in more detail below under point 7, if an obligated entity claims the RECs associated with renewable energy that is generated and used on the customer's side of the meter, then the customer's load that has been served on site should be added to the obligated entity's retail sales. RECs that are associated with energy that is exported to the grid should be treated identically with other grid-distributed renewables with respect to separability of RECs and energy.
City of San Diego	Power that is exported into the grid by an eligible DG facility but not sold to an obligated entity has essentially been sold to the local utility for free; the associated REC, however, is retained by the DG owner.
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	No Comment
PG&E	As explained above, net metering projects export power to the grid, and receive a bill credit, but do not "sell" this power. This power should be included as meeting the RPS standard. …

4a. Interaction with Utility net metering tariffs: Should an eligible DG facility participating in net metering be allowed to participate in the RPS while maintaining its net-metered status?

Bonneville Environmental Foundation	Yes. The costs of any alternative would likely outweigh the benefits. However, the issue goes beyond participation in the RPS. The kWhs the systems generate create the same environmental benefit regardless of which side of the meter the electrons flow. The point is that the system owner owns the environmental benefits of every kWh the system produces. Those benefits can flow into an RPS or to a tag marketer or to the customer. The choice should be up to the customer.
Capstone	Eligible DG that participates in the net metering program should be eligible for participation in the RPS and maintain its net metering status.
CAL SEIA	Separating the sale of RECs from the sale of electricity adequately addresses this issue. Allow the PV generator to be the owner and seller of the RECs to the REC customer of their choice.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	The CPA believes that a customer should be able to benefit from the market value of RECs or "green tags", in recognition of that customer's election to invest in renewable DG.
Green Power Institute	It is important to keep the topics of net metering and RPS participation separate for renewable DG. RPS regulations include certain specifications, some still under development, that must be met for PPAs that are awarded in sanctioned RPS solicitations. However, there is no requirement that all renewable energy counted towards an APT be procured through any particular type of sales arrangement. The same approach should be applied to renewable DG. Whether or not a renewable DG has a net-metering arrangement with its utility should be unrelated to its eligibility to participate in the RPS program.
City of San Diego	Eligible DG facilities participating in net metering should be able to participate in the RPS program by selling RECs associated with their gross output.
Vote Solar Initiative	Yes, net metered DG should be eligible to participate. We believe that all energy generated by renewable DG should be creditable towards the RPS.

4a. Interaction with Utility net metering tariffs: Should an eligible DG facility participating in net metering be allowed to participate in the RPS while maintaining its net-metered status? (continued)

Enertron Consultants	An eligible DG facility participating in net metering (e.g. solar PV < 1 MW) should be allowed to participate in the RPS while maintaining its net metered status. The RECs owned by the DG facility owner should be eligible for the RPS when procured by an RPS-obligated entity. Some have argued earlier in this proceeding that the payments under net metering contracts effectively "subsidize" renewable DG installations by paying the full retail rate for energy from these facilities, and therefore the RECs associated with these installations should transfer, for free, to the local distribution utility. The recent FERC declaratory order regarding PURPA contracts for QFs sets a precedent that negates this contention. This order states that "contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent express provision in a contract to the contrary)". Similarly, the presence of a net metering contract does not convey the RECs to the utility, since there is no express provision in the met metering agreement that conveys the RECs. Therefore net metered DG facilities should be allowed to participate in the RPS and the utility can appropriately compensate the DG owner to procure the RECs.
Mainstay Energy	DG facilities involved in net metering should still generate RPS-eligible RECs as well. There are essentially two possibilities for a net metering agreement: • Electricity only • Electricity and RECs If a net metering agreement only involves electricity, then ownership of the RPS-eligible RECs should remain with the site owner, who can retire them or sell them to an aggregating entity. Alternatively, a net metering agreement could also involve the transfer of RECs to the [load serving entity], if this were to be specified clearly in the agreement, and the site owner received appropriate compensation.
SDG&E	Because of the administrative costs involved, SDG&E typically limits participation in our RPS solicitation to 1 MW or greater. We believe it most efficient to leave such smaller purchases to bilateral arrangements.
SCE	DG interconnected under a net metering... tariff should not be allowed to participate in RPS. Exported energy from [net metering] projects is properly linked to the customer's on-site electricity consumption, against which it is netted.
PG&E	Power used on site, as well as power delivered to the grid from net metering projects should count toward the utility RPS requirement.

4b. Interaction with Utility net metering tariffs: Is it appropriate to allow exported energy within the netting period to count for RPS purposes while being credited against that customer's grid usage?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	To the extent that it is possible to measure or estimate the gross amount of power produced by the DG, the DG owner/end user should be able to obtain the market value of the full production level, regardless of the amount exported back under net metering.
Green Power Institute	No Comment
City of San Diego	The net metering program is designed to encourage installation of customer-side renewable energy. Eligible DG participation in the RPS provides additional incentive for installing such generation, but does not provide an excessive subsidy.
Vote Solar Initiative	see no conflict in a renewable DG owner receiving credit for both the commodity element of exported electricity, and for the renewable attributes of that electricity.
Enertron Consultants	It is also appropriate to allow exported energy within the netting period to count for RPS purposes while being credited against that customer's grid usage. This is no different than a central station facility selling renewable energy to the utility. In this case, the price that is being paid to the net metered customer is the retail rate in effect at the time that the exported energy is delivered to the grid – that is the contract rate that the net metered customer has entered into with the utility. Since this is renewable energy that is being delivered to the grid, it should be counted for RPS purposes. Using the inverter to measure the AC output of the DG facility will assure that the correct amount of renewable energy is being counted for purposes of the RPS.
Mainstay Energy	Again, if the RECs are unbundled from the power at the point of generation, the difference between the exported power and the power consumed on site becomes irrelevant. All RECs are RPS-eligible.
SDG&E	No Comment
SCE	No Comment
PG&E	Power used on site, as well as power delivered to the grid from net metering projects should count toward the utility RPS requirement.

5a. Interaction with public subsidies: Should an eligible DG facility that has received public subsidies of its capital costs from CEC be allowed to participate in the RPS?

Bonneville Environmental Foundation	No Comment
Capstone	Eligible DG that receives capital cost incentives from the Commission or the California Energy Commission should be allowed to participate in the RPS and be eligible for SEP payments to bridge the gap between costs and the market price of the power Capital incentives provide a generator with a means of funding the development costs of a facility. RFS obligated entities should not be prevented from accessing an eligible source of electricity because of the particular way the facility generating that electricity was financed.
CAL SEIA	All renewables receive subsidies, and these funds were not conditional on giving up REC ownership rights. Entities receiving rebates from the CEC or CPUC that generate RECs should be the owner of the RECs and be allowed to do with its RECs what it feels provides the best economic return.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	For any DG that received a public subsidy of the capital cost, there was a public good created in proportion to the public subsidy contribution to the system cost. The dilemma is to determine if the public investment essentially bought "energy" or "green attributes" from its investment in renewable power technology. Some might argue that the public bought an incremental ownership interest only in the green attributes, and should own all/some of the green attribute. Others might argue that the energy and green attributes cannot be separated. To continue to incent private investment in DG power systems, we think it important to assign the public "rights" to the public's proportional investment share of the DG system cost.
Green Power Institute	The RPS program (SB 1078) was established in conjunction with the state's renewable energy programs (SB 1038). Subsidies that are needed in order to enable RPS program goals to be reached are provided through the various programs run by the CEC. Since the original establishment of the CEC's renewables programs in AB 1890, renewables in different categories (existing, new, emerging) have been treated differently. There is no reason why this shouldn't continue to be the case in the future. …. The answer is that yes, new DG installations that receive public subsidies yet to be awarded should be eligible for the RPS, just as new grid-distributed renewables are eligible to receive public subsidies if their costs are above the market referent price.
City of San Diego	Eligibility for participation in the RPS program should be determined on the basis of technology, not the source of funding for capital costs. The owner of the eligible DG facility holds the REC property right and is free to sell the REC to an RPS-obligated entity...

5a. Interaction with public subsidies: Should an eligible DG facility that has received public subsidies of its capital costs from CEC be allowed to participate in the RPS? (continued)

Vote Solar Initiative	DG facilities that have received public subsidies for capital costs should be allowed to participate in the RPS. The fact that the systems are subsidized in no way impacts the legal ownership of the systems, or the fruits of the system's production. …
Enertron Consultants	An eligible DG facility that has received public subsidies of its capital costs from the Commission or CEC should be allowed allowed to participate in the RPS
Mainstay Energy	DG facilities which have received Commission or CEC funds should still have full title to their RECs. This should be stated clearly in such agreements. It does not represent a second subsidy to the owner any more than a net metering agreement does. A subsidized facility should have full title to both power and RECs generated. The deployment of new renewables and the overall public good is better served by a vibrant DG REC market with clear title issues than highly complex debates over percentage of public moneys received.
SDG&E	SDG&E does not believe DG facilities should be allowed sell to a utility if they are on a [net metering] tariff. Any other public subsidies should be treated the same as for any other renewable supplier who may get PTC or other public funding. When bidding for DG contracts, these subsidies should be included in the bid. For administrative purposes, SDG&E believes such sources should be excluded from eligibility by allowing contracts only through a bilateral rather than RFO procurement process.
SCE	Only DG projects whose entire output is used to serve on site load are eligible for the CEC's renewable capital cost buy down program and the CPUC's self generation incentive program, as such programs are currently structured. As discussed in the response to Question 1 above, SCE recommends that this generation not be eligible for RPS participation. Therefore, these projects' receipt of public subsidies would not be relevant to the RPS. On the other hand, those DG projects which do sell power through the grid under the arrangements described in SCE's response to Question 1 might apply for SEP payments in a manner similar to other renewable resources participating in RPS.
PG&E	Again, the concept of "participation in the RPS" must be broken into constituent parts for analysis. Power generated by DG facilities that received ratepayer subsidies should count toward the utility RPS requirement. …

5b. Interaction with public subsidies: Does the provision of public subsidy represent a second subsidy to the DG owner?

Bonneville Environmental Foundation	If the goal is the expansion of the market, then allow the customers to use a state subsidy and sell the tags if they wish. The result will simply be more systems installed.
Capstone	The provision of a public subsidy does not render the renewable output a public good and payment for that output would not necessarily represent a second subsidy. The public good provided by many incentive programs includes air quality goals, energy efficiency and peak load reduction. For example, the California legislature established the goal of the California Self Generation Incentive Program as being "…to reduce demand for electricity and reduce load during peak periods" PU Code 300.15(b). Clearly the public benefit of the incentives is the energy that is not consumed or taken from the grid as a result of the DG facility's output. The program does not provide for the energy produced by the facility to become a public good.
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	Indeed, the public good is served in so many ways by DG renewables, including reduced chances of transmission failure, better air quality, less foreign dependence on fossil fuels. We should not be looking for ways to take money back from these DG pioneers —rather we should be pleased that renewable DG owners can achieve an additional market benefit and improve payback on projects that already have a relatively low rate of return.
SDG&E	No Comment
SCE	No Comment
PG&E	No. The "renewable output" is not a public good, it is electric energy produced by a renewable resource. The DG owner should receive compensation for electricity delivered. The public subsidy of renewable DG means that the DG developer should not receive a second subsidy, in the form of compensation for the renewable attribute of the generation, for developing the one renewable (DG) resource.

5c. Interaction with public subsidies: How should the RPS-eligible energy be counted towards the RPS, if at all?

Bonneville Environmental Foundation	No Comment
Capstone	The RPS eligible energy that receives another incentive should generally be treated equally with any other eligible energy for the purposes of the RPS. It should not be discriminated against on the basis of the source of capital funding. …
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	…in cases where a public subsidy of 50% of the system occurred, the "public" should own its share (e.g. 50%) of the renewable attribute, and should assign that at no additional cost to the load serving entity (regulated utility or ESP). The principle should adhere that the DG owner/end user retains a proportional interest in the green attributes, corresponding to the size of the final private3 investment made. The "private share" would play by whatever rules emerge from answering Questions 2-4, 6, and 8 about ownership, accounting, net metering, etc. The value of the privately-held renewable attributes should be set either through a market/trading mechanism or as an average of the equivalent SEP payments to central station renewable generation.
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	No Comment
Enertron Consultants	Allowing the PV owner to be paid for the renewable attributes the PV system produces helps to further reduce the already considerable investment of the PV owner and may be another way to encourage others to install PV. The energy from these systems should be counted toward the RPS, because these systems are part of the solution for the state to reach its RPS goal.
Mainstay Energy	See answers to 5a and 5b above.
SDG&E	No Comment
SCE	No Comment
PG&E	The "RPS eligible energy" is energy from a renewable resource subsidized by ratepayers. The subsidy for renewable DG stands in the place of any special compensation for the renewable attribute of the generation arising from the RPS program (e.g., a "REC" payment). Utility ratepayers have already compensated the DG developer for the renewable nature of the output, so the generation should count toward the subsidizing utility's renewable obligation without further compensation to the DG developer.

5d. Interaction with public subsidies: Treated similarly or differently than SEP payments for central station

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	The CEC's renewables programs have always treated grid-distributed renewables differently than DG (emerging) renewables with respect to the awarding of subsidies. Prior to the RPS program, new grid-distributed renewables had to bid into auctions for production credits, while emerging technologies were offered a buy-down program related to their capital cost. With the institution of the RPS program, new grid-distributed renewables are now eligible for SEPs, the magnitude of which for a given facility are determined by a bid from the facility owners, and a CPUC-determined market referent price. Whether, or more particularly when, it might be appropriate to apply a market-based subsidy, rather than the current buy-down program which awards a fixed proportion of the qualifying capital cost, to emerging technologies is a policy question. The GPI's opinion is that that point has not yet been reached.
City of San Diego	No Comment
Vote Solar Initiative	No Comment
Enertron Consultants	The public subsidies reduce the capital cost of the DG facility to its owner, but the owner is still making a larger capital investment than they would have, had they invested in a central-station renewable facility. For example, a PV system owner today can receive a subsidy of \$3.80 per watt (\$3,800 per kilowatt) for installing a solar system, but the owner paid at least another \$3.80 per watt (and probably more) for their PV system. In comparison to a central-station wind farm, which can be installed at about \$1000 per kilowatt at this time, the PV owner is still spending close to 4 times what the wind farm owner spent. Therefore, the subsidy makes it possible for people to invest in PV systems because they are willing to accept a long-term payback on their investment. Even though the PV owner received a public subsidy funded by ratepayers, the PV owner is still making a substantial monetary investment in their system.
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	On the other hand, those DG projects which do sell power through the grid under the arrangements described in SCE's response to Question 1 might apply for SEP payments in a manner similar to other renewable resources participating in RPS.

5d. Interaction with public subsidies: Treated similarly or differently than SEP payments for central station (continued)

PG&E	Renewable DG developers should receive no RPS incentives for development that is already being subsidized by the SGIP or other subsidies discussed above. The Commission may wish to exempt certain renewable DG from the bid process by which the seller establishes its position in the queue and winning bids are chosen. Depending on the size of the net generation that the renewable DG developer wishes to sell, the Commission may determine that the renewable DG developer may receive no less than the market price referent for the amount of deliveries it has noted in its memorandum of understanding with its subsidizing utility.

5e. Interaction with public subsidies: Others

Bonneville Environmental Foundation	It is up to the state to decide if the pubic subsidy provided by the state should be in exchange for state ownership of the tags. However, if the state is not covering the entire above market cost of the system, then the state should not own all the tags. The administrative costs associated with claiming the tag may outweigh the benefits.
Capstone	The legislation makes it clear that the SEP is paid as a subsidy to bridge the difference between the market value of the power produced and the cost of producing that power. Any facility that receives an incentive for the purpose of encouraging a public benefit other than the purpose of the SEP payment should receive an SEP payment as appropriate to bridge the gap between the cost of production and the market value of that production. Only if the intent of a subsidy that is already being received by the facility is to achieve the same effect as the SEP, should the SEP payment be reduced.
CAL SEIA	CAL SEIA recommends that this regulatory structure be studied for three full years at which time both the REC policy and PV rebate policy should be reviewed. If this study period is during calendar years 2004-2006 and the analysis and study is done in late 2006 and early 2007, then it can be used as input for the reauthorization of the Self-Gen funding that is now due to sunset on Jan. 1, 2008.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	No Comment
PG&E	No Comment

6a. Implications of DG participation for REC tracking and potential trading: How does participation of renewable DG affect this REC system?

Bonneville Environmental Foundation	The state should be careful not to place expensive administrative burdens on small systems. Again, the costs will exceed the benefits.
Capstone	No Comment
CAL SEIA	A REC tracking system is a very good idea for RECs used to meet RPS compliance requirements. The manner by which RECs are sold to non-RPS entities is not of relevance to the RPS and therefore does not need to be addressed by the RPS program.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	As explained in our answer to Question 2, DG owners should be encouraged to enter agreements to track and quantify their production. Any DG owners entering such agreements could be tracked in an RPS system. If there is a REC trading system, DG RECs (including the proportional amounts of privately-owned DG) should be fully able to compete for the value available to such RECs.
Green Power Institute	The energy used on-site will have to be metered in order for RECs to be verified, and the tracking system under development at the CEC should treat all RECs the same way. If the Commission ultimately chooses to adopt a REC trading system as an RPS compliance mechanism, then RECs associated with customer-side renewables should be able to be sold to any willing buyer. If the willing buyer is an obligated entity using the REC for RPS compliance, then the energy associated with the REC should be added to the purchasing obligated entity's retail sales.
City of San Diego	No Comment
Vote Solar Initiative	Rules governing the transfer of REC should be developed with an eye to ensuring the integrity of the REC trading system, and contracts consistent with that goal should be required.
Enertron Consultants	The REC tracking system that the CEC ultimately develops should allow the participation of renewable DG. However, the CEC's tracking system does not need to specifically include small, customer-sited renewable generation or solar water because this is under development elsewhere. The Pace Energy Project is spearheading a project that is aggregating small, customer-sited generation into a central registry to facilitate its participation in renewable certificate markets.
Mainstay Energy	Any new tracking system should allow participation of DG from its inception. This could be done most efficiently with the use of aggregator accounts representing the output of many smaller systems.
SDG&E	No Comment
SCE	To the extent that a DG project would participate in RPS under the conditions described in SCE's response to Question 1 above, it could be addressed in an RPS tracking system in the same manner as other renewable resources.

6a. Implications of DG participation for REC tracking and potential trading: How does participation of renewable DG affect this REC system? (continued)

PG&E	The CPUC has not yet defined the renewable attributes that must be conveyed along with renewable energy. The CEC is charged with developing a system to identify and track renewable attributes. If the CEC and CPUC create "renewable energy credits" or RECs as a unit of measurement of the attributes associated with a unit of energy, they will simply have to devise a means of recording the existence of RECs that separate from energy conveyed in a commercial transaction (such as utility procurement from a renewable generator).

6b. Implications of DG participation for REC tracking and potential trading: Must a REC from a DG facility represent the same amount of output and be retired in the same fashion as a REC from a central-station facility?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	RECs from DG generators should be treated identically to RECs from grid-distributed renewable generators, with the one exception being that RECs can be separated from energy for energy used on-site, but with the two stipulations that the RECs can only be transferred to the DG's own utility or energy service provider, and the energy that is used on-site is added to the provider's retail sales.
City of San Diego	DG participation in a REC trading program would be no different than treatment of a central station facility. If certain reporting or certification requirements are particularly onerous or costly, special provisions may be made for DG facilities below a certain size. For example, DG owners may be permitted to self-certify eligibility and REC output levels, with enforcement provided through spot auditing.
Vote Solar Initiative	In the development of a REC trading system, allowances should be made for the typical output of renewable DG systems. In order to accommodate this goal, RECs could be issued in smaller or partial units, or a small system could be allowed to bank its output and aggregate over a longer period of time, or provisions could be made for aggregators to bundle the output of multiple small systems.
Enertron Consultants	These RECs would be retired in the same fashion as RECs from central-station renewable facilities.
Mainstay Energy	RECs from DG facilities should be tracked, traded, and retired in the same fashion as central station RECs.
SDG&E	Subject to the restrictions we have outlined above, SDG&E would treat RECs from DG renewables the same as RECs from other renewable entities. This scenario demonstrates that REC trading makes sense.
SCE	No Comment
PG&E	The CEC may create RECs in any denomination of output it deems to be reasonable. The CEC tracking mechanism should ensure that every DG REC arises from non-subsidized DG generation from a renewable facility. DG RECs should be "retired" whenever they are conveyed to a REC-obligated entity.

6c. Implications of DG participation for REC tracking and potential trading: What impact would the participation of DG have on the REC trading system?

PG&E was the only respondent commenting on this question. PG&E wrote: The Commission should make sure that any trading system does not create unreasonable administrative burdens for small projects. PG&E now has nearly 4000 solar projects on line on its system, most of them quite small, and nearly 100 new projects come on line [soon]…

7a. Interaction with Retail Sales Accounting: How should energy and attributes from a DG facility be accounted for in terms of calculating retail sales?

Bonneville Environmental Foundation	Again, tracking small DG output to offset an RPS requirement is potentially a huge expense with little economic gain. Leave the tags with the system owners and focus attention where attention is needed.
Capstone	No Comment
CAL SEIA	The retail sales of an IOU are measurable and should be used as the basis for RPS requirements. As such, any DG that reduces those retail sales will help IOUs by reducing their RPS requirements thus ensuring accelerated compliance with California's RPS goals. If RECs and electricity are treated separately it will be very easy to track where DG RECs are going.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	From a public policy perspective, it would be ideal if the gross DG production levels (including DG power consumed on-site) could be counted toward a renewable portfolio "bubble" serving a service area. This “bubble” would consist of both utility-procured renewable energy and the power produced by end user-investment in DG. However, to accomplish this might keep scores of accountants and modelers busy, at substantial cost to ratepayers and DG owners. A possible compromise would be to count the estimated or measured gross DG production against the retail sales level. While this might give “extra credit” to DG, and enable utilities to reach their RPS targets faster, it would be consistent with the established State policy to encourage DG. Moreover, this approach would save considerable expense in trying to determine what retail sales would have been absent the DG. Giving DG full credit for its gross production is necessary and consistent with allowing the DG owner to sell RECs for the private proportion of investment in DG.
Green Power Institute	The APT for an RPS obligated entity is determined on the basis of a program specified percentage of that entity's total retail sales. New customer-side DG, whether renewable or not, reduces the retail sales of the utility or ESP that previously that load, and therefore reduces the amount of renewable energy that an entity must procure in order to achieve its APT. Thus, even if customer-side-of-the-meter renewable DG is not counted towards an obligated entity’s APT, it does reduce the obligated entity’s ultimate renewable procurement requirement. The same is equally true for non-renewable DG. The reduction in an obligated entity’s ultimate renewable procurement requirement due to departing load leads to the following paradox: If RECs are issued for energy that is generated and used on the customer side of the meter, then, if no adjustment is made to the retail sales volume of the utility for the departed load, a 1 MWh REC from a new DG generator would bring the utility closer to reaching its RPS requirement than a 1 MWh REC from any grid-distributed renewable generator, new or existing. This violates the fairness principle that should guide policy making for including renewable DG in the RPS program. The simple solution is to add the amount of energy represented by the DG REC, which by definition is the amount of departed load represented by that installation, into the obligated entity’s retail sales. In that way, the RECs associated with grid-distributed generators and DGs would be of equal value to the utility.

7a. Interaction with Retail Sales Accounting: How should energy and attributes from a DG facility be accounted for in terms of calculating retail sales? (continued)

City of San Diego	No Comment
Vote Solar Initiative	Consistent with preserving the integrity of the principles of a REC trading system, when a REC is purchased from a DG system owner, it is only the renewable attribute that is purchased, and not the commodity electricity.. Therefore, the energy produced by a renewable DG system and consumed on-site should not be counted towards the total retail sales of an RPS-obligated entity.
Enertron Consultants	For purposes of IOU compliance with the RPS, a service-territory perspective should be taken, and assuming proper compensation is made for the DG RECs, the gross output of eligible DG energy within the IOU's service territory should be credited to its RPS targets, without adjusting retail sales to reflect on-site generation and use. By taking this approach, the utilities receive some benefit and will hopefully encourage the use of DG in their service territories.
Mainstay Energy	Power and RECs should be accounted for independently.
SDG&E	No Comment
SCE	No Comment
PG&E	Consistent with D;.02-10-062, all renewable DG generation should be counted towards retail sales, and all renewable DG should count towards the obligated entity's satisfaction of the annual renewables goal.

7b. Interaction with Retail Sales Accounting: Should the quantity of RPS-eligible DG energy used on-site be added to the total amount of retail sales of the obligated entity?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	see answer to 7a above
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	Giving distributed generation full credit for its gross production is necessary and consistent with allowing the distributed generation owner to sell RECs for the private proportion of investment in distributed generation.
Green Power Institute	See answer to 7a.
City of San Diego	To be consistent, and to ensure that statewide RPS targets are not compromised by participation of customer-side DG, the retail sales figures should be adjusted to account for self-generation. For purposes of calculating the annual renewable procurement obligation, the retail sales of the RPS-obligated entity should be increased by the amount of RECs it purchases from customer-side DG. If the RPS obligation were extended to customers with on-site generation, then such an adjustment would not be necessary, since the customer would be responsible for the RPS associated with its self generation.
Vote Solar Initiative	No Comment
Enertron Consultants	DG energy within the IOU's service territory should be credited to its RPS targets, without adjusting retail sales to reflect on-site generation and use.
Mainstay Energy	The output of a DG facility reduces retail sales for the entity it interconnects with. Retail sales should not be adjusted to reflect onsite generation and use. The RPS obligated entity need only procure RECs in proportion to actual retail sales.
SDG&E	Because IOUs are only purchasing the RECs and not the energy, it is not necessary to adjust retail sales to account for DG customer related load.
SCE	The language in D.02-10-062 is clear: Procurement needs are to be calculated on the basis of total retail sales. Power generated by DG projects which is consumed by a customer on site falls outside this category and should not be included in the calculation. Surplus power purchased by the IOU from DG projects under the arrangements recommended in SCE's response to Question 1 above should be counted for purposes of IOU compliance with the RPS. Surplus power sold to an obligated entity outside the IOU's service area should be counted for purposes of that entity's compliance.
PG&E	Yes, however, PG&E expresses no opinion at this time regarding the "property right" mentioned in the question. The Commission should seek comments on the legal issue of whether the passage of SB 1078 created a new property right a renewable generator.

7c. Interaction with Retail Sales Accounting: How should DG output be accounted for if the facility sells its output to an entity outside the IOU's service area?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	If RECs and electricity are treated separately it will be very easy to track where DG RECs are going. Specifically, all RECs can be measured by a commercial-grade meter regardless of whether the electricity associated with those RECs is used behind-the-meter or is exported to the grid.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	The CPA understands that the primary purpose of including the DG provision for RPS in the Commission's prior decision was to make it in the regulated utilities' interest to facilitate DG. Therefore we think it essential that the DG production "accounting credit" accrue to the load-serving entity (utility or ESP). This would mean that any REC also would need to remain attached to a specific service area or ESP.
Green Power Institute	No Comment
City of San Diego	No Comment
Vote Solar Initiative	No Comment
Enertron Consultants	If a facility sells its output to another RPS-obligated entity outside the IOU service area, there will not be a net metering contract with the IOU and therefore that DG facility should not be counted as an eligible DG facility for that IOU.
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	Surplus power sold to an obligated entity outside the IOU's service area should be counted for purposes of that entity's compliance.
PG&E	If the distributed generation developer did not receive ratepayer subsidies, and the project makes wholesale sales outside the IOU service area, the IOU where the project is located should be credited with the output towards its RPS standard. For example, if small wind projects in PG&E's service area, which were not subsidized by PG&E ratepayers, sell their output to SCE, the output should count toward SCE's RPS obligation.

8a. Interaction with MPR and SEP: How should eligible DG facilities be considered in terms of the solicitations, market price referents, and possible supplemental energy payments that are part of the RPS structure for most central-station systems?

Bonneville Environmental Foundation	No Comment
Capstone	No Comment
CAL SEIA	It is assumed that RPS-obligated entities will purchase only the lowest priced RECs. PV DG facilities should be allowed to participate in RPS solicitations, and the participation should be allowed as providers of either: a) only RECs; or, b) RECs plus its associated electricity. This has already been done in Nevada. It is unlikely that PV RECs or PV electricity will be competitive at this time with other sources of RECs or green electricity such as wind power systems. CAL SEIA does not feel that any supplemental energy payments or other funds are necessary for PV as long as the Self-Generation Incentive Program and Emerging Renewables Buydown programs are in place and fully funded.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	See our related answers to questions #5 and #6 above. Essentially, DG facilities should have their allowable RECs or other equivalent measures valued similarly to the valuation of central station RECs, taking into consideration different line loss characteristics. For on-site DG consumption versus net-metered DG power exported to the grid. DG facilities that received public subsidies would participate in a valuation system for the proportional amount of the facilities' output paid for with non-public investment. We note that any DG facilities larger than 1.5 MW probably did not receive any public investment, and thus would be seeking valuation of its full production levels.
Green Power Institute	Eligible DG facilities should be able to bid into RPS solicitations for energy that they plan to sell to the grid. However, for energy that will be produced and consumed on the customer's side of the meter, participation in a solicitation for energy sales does not work. … The CEC program for new grid-distributed renewables, which are considered to be commercial technologies, is market based, relying on competitive bids from developers. The current buydown program for emerging technologies is not market based, in recognition of the pre-commercial status of the technologies that are being developed. It is the opinion of the GPI that this is appropriate as long as DG is considered to be pre-commercial. However, if and when these technologies do become commercially viable, it will be appropriate to develop a market based support program for them. There is no imperative to develop that system at this point in time.
City of San Diego	If the utility is purchasing only RECs from the DG facility and not the underlying energy, then there is no interaction with the renewable energy solicitation process involving market price referents and supplemental energy payments.
Vote Solar Initiative	No Comment
Enertron Consultants	DG participation in the RPS should be enabled through a mechanism independent from the procurement of central-station renewable power.
Mainstay Energy	No Comment

8a. Interaction with MPR and SEP: How should eligible DG facilities be considered in terms of the solicitations, market price referents, and possible supplemental energy payments that are part of the RPS structure for most central-station systems? (continued)

SDG&E	No Comment
SCE	No Comment
PG&E	The solicitations, market price referents, and supplemental energy payments are used to procure renewable resources as part of the utility's resource plan. DG is not part of the resource plan; it exists within the utility service territory whether the utility has solicited or not. It is difficult to conceive how DG would be factored into the utility's wholesale procurement process. The MPR-SEP structure is not needed to encourage DG development.

8b. Interaction with MPR and SEP: Should eligible DG facilities be allowed to participate in RPS solicitations, on an individual or aggregate basis?

Bonneville Environmental Foundation	Given the prices the voluntary (green power) market is willing to pay for solar tags, it is difficult to see how an aggregation of small DG would be better off bidding against large central station facilities in an RPS solicitation. …
Capstone	DG facilities should be able to participate in the RFS and be eligible for SEPs. This includes participation in solicitations. But, as discussed in answer to question 2, the [RPS] obligated entities should set aside some required energy that small DG less than 2MW should can fill by way of a standard offer agreement. This offer should be available until such time as the full 20 percent RPS target is achieved.
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	Eligible DG facilities should be able to bid into RPS solicitations for energy that they plan to sell to the grid. However, for energy that will be produced and consumed on the customer's side of the meter, participation in a solicitation for energy sales does not work.
City of San Diego	If the DG facility, either individually or aggregated, wants to sell bundled energy and RECs to the utility, it should be able to participate in the RPS solicitation and be eligible for supplemental energy payments in the event that their winning bid exceeds the established market price referent.
Vote Solar Initiative	PGC-funded buydowns and SEPs are separate entities. There is no reason why eligible customer-sited DG should not be allowed to receive both.
Enertron Consultants	DG facilities should be considered separately from the central-station renewable facilities. DG participation in the RPS should be enabled through a mechanism independent from the procurement of central-station renewable power.
Mainstay Energy	Eligible DG facilities should be allowed to participate in RPS solicitations on an aggregated basis, through a qualified aggregating entity. The mechanisms for this participation should be certificate based, not contract path based.
SDG&E	No Comment
SCE	No Comment
PG&E	DG facilities should be able to participate in RPS solicitations. Due to the lack of economics stemming from their small size, it may be cost-effective for the renewable DG developers to aggregate.

8c. Interaction with MPR and SEP: Should a separate market price referent for distributed generation be established?

Bonneville Environmental Foundation	No Comment
Capstone	The market price established for DG should be the same as that for all eligible electricity. However, small renewable DG will have greater above market costs than larger systems, necessitating higher SEP payments for small facilities.
CAL SEIA	No Comment
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	MPRs and SEPs are not relevant to energy that is produced and used on the customer side of the meter.
City of San Diego	Note that the market price referent must be for a technology and location that provides comparable energy (i.e., distributed generation). The SEP is simply a mechanism making up the difference between the market price referent (up to which the utility pays) and the winning bid price. It seems reasonable to expect that any winning bidder would receive its bid price regardless of the source of payment (i.e., SEP or utility).
Vote Solar Initiative	No Comment
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	No Comment
SCE	Subject to the conditions outlined in SCE's response to Question 1 above, DG facilities should be treated in a manner consistent with other participants.
PG&E	The purpose of the market price is to ensure that ratepayers do not pay more than the "market price" for energy, even if the energy is generated by a more expensive technology. The difference between the bid price and market price is made up by the supplemental energy payments. In the case of renewable DG, the Legislature has already established the above-market subsidy for capital development of renewable DG. There is no need for further above-market price subsidies.

8d. Interaction with MPR and SEP: Should customer-sited DG be allowed to receive SEP in addition to PGC-funded capital cost buy-downs, or instead of these incentives?

Bonneville Environmental Foundation	No Comment
Capstone	As discussed in answer to question 5. eligible renewable energy resources should be eligible for SEP payments without regard to the source of their capital funding. Capital cost buy-downs are not intended to bridge the gap between the cost of production and the market value of that production and should not be a factor affecting the availability or magnitude of any potential SEP.
CAL SEIA	CalSEIA does not feel that any supplemental energy payments or other funds are necessary for PV as long as the Self-Gen and CEC Emerging Renewables Buydown programs are in place and fully funded.
California Coalition of Fuel Cell Manufacturers	No Comment
California Power Authority	No Comment
Green Power Institute	Since the inception of the CEC's renewables program, emerging technologies have been supported by a different account with different rules than new, grid-distributed technologies. Allowing DGs to participate in the RPS does not imply that the two-account approach should not be continued in to the foreseeable future. Certainly, no facility should be able to dip into both accounts.
City of San Diego	The SEP is simply a mechanism making up the difference between the market price referent (up to which the utility pays) and the winning bid price. It seems reasonable to expect that any winning bidder would receive its bid price regardless of the source. Bidders receiving PGC-funded capital cost buydowns would be expected to factor those buydowns into their calculation of costs when submitting a bid, and in a competitive market would risk losing the solicitation by submitting a bid that is higher than their actual cost. [Perhaps split the two funding sources: below a certain size you get net metering and buydown, above that size you get RPS eligibility and SEP]
Vote Solar Initiative	PGC-funded buydowns and SEPs are separate entities. There is no reason why eligible customer-sited DG should not be allowed to receive both.
Enertron Consultants	No Comment
Mainstay Energy	No Comment
SDG&E	SDG&E does not believe customer-sited DG should be allowed to receive SEP in addition to PGC-funded capital cost buydowns. Please refer to our response above for further explanation.

8d. Interaction with MPR and SEP: Should customer-sited DG be allowed to receive SEP in addition to PGC-funded capital cost buy-downs, or instead of these incentives? (continued)

SCE	No Comment
PG&E	No, the DG developer is not entitled to duplicate incentives; SEP payments should be available only for output which is not otherwise subsidized.

8e. Interaction with MPR and SEP: Should DG participation in the RPS be enabled via mechanisms independent from the procurement of central-station renewable power?

PG&E was the only respondent to this question. PG&E wrote: Yes. As indicated above, since DG eligibility for REC compensation will be limited to the amount of non-subsidized net output, the DG developer simply needs to indicate to the CEC the amount of electricity it can offer and when this is procured…

8f. Interaction with MPR and SEP: Others.

The Green Power Institute was the only respondent to this question. The Green Power Institute wrote: The Energy Commission program for new grid-distributed renewables, which are considered to be commercial technologies, is market based, relying on competitive bids from developers. The current buydown program for emerging technologies is not market based …

9. Eligible DG technologies: Add or subtract particular technologies?

Bonneville Environmental Foundation	The list is sufficient
Capstone	Eligible DG technologies. Capstone encourages the Commissions to consider including oil field flare gases as an eligible technology. While this is not usually thought of as a renewable fuel, it is an unavoidable by-product of other processes. Flare gas will be produced and are usually wasted. The development of the RPS provides an excellent opportunity to recognize the existence of this wasted energy source and to provide an opportunity for this energy to be used.
CAL SEIA	The DG list is acceptable.
California Coalition of Fuel Cell Manufacturers	Finally, we strongly encourage you to expand the definition of eligible DG technologies to include fuel cells operating on natural gas. SB 1038, also enacted in 2002..., among other things, authorized the PUC to consider a technology's efficiency. and emissions profile when establishing rates and fees. “Ultra-clean” is defined as technologies that meet the Air Resources Board’s 2007 emission standards for DG today; the only technology meeting this definition is fuel cell technology.
California Power Authority	We have no additions or subtractions to the technology list.
Green Power Institute	The GPI knows of no reason to apply different criteria for qualification as renewable for DG than for grid-distributed renewables. The key is that fossil-fuel powered DG not be allowed to participate in the RPS program.
City of San Diego	The list provided in D.02-10-062 is sufficient.
Vote Solar Initiative	Seems sufficient.
Enertron Consultants	no comment

9. Eligible DG technologies: Add or subtract particular technologies? (continued)

Mainstay Energy	Perhaps a clarification on fuel cells: "fuel cells using renewable fuels, or hydrogen generated from qualified renewable power sources," [*sic*]
SDG&E	No comment
SCE	The list provided in D.02-10-062 is sufficient
PG&E	The list of renewable technologies provided on pages 19-21 of D.02-10-062 includes all of the technologies defined as "renewable generation" by SB 1078.. Since the Commission is presently considering the inclusion of direct generation output from renewable technologies in the RPS, PG&E believes that the definition of eligible DG should be identical to the definition of renewable technologies in SB 1078.

Notes

[1] CPUC; Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program; filed April 22, 2004; Rulemaking 04-04-026.

[2] Energy Commission; Renewables Portfolio Standard Eligibility Guidebook, May 2004, 500-04-002F.

[3] For clarification, here “private” means the customer, end-user, or a third-party owner/developer of the DG, and may include investments by state and local public agencies. “Public investment” refers to ratepayer or taxpayer incentives such as those administered by the CEC’s emerging renewable account or the CPUC/IOU’s Self Generation Incentive Program.